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February 5, 2004

HAND DELIVERED

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RE: ***P.S.C. Case No. 2002-00475***

Dear Mr. Dorman:

Enclosed please find enclosed and accept for filing the original and ten copies of the Responses of Kentucky Power Company d/b/a American Electric Power to the Supplemental Data Requests propounded on January 22, 2004. Copies have been served on all parties of record.

If you have any questions, please do not hesitate to contact me.

Sincerely yours,

STITES & HARBISON PLLC

Mark R. Overstreet

cc: Counsel of Record

KE057:KE157:10506:1:FRANKFORT

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY d/b/a AMERICAN ELECTRIC POWER, FOR APPROVAL, TO THE EXTENT NECESSARY, TO TRANSFER FUNCTIONAL CONTROL ONLY OF TRANSMISSION FACILITIES LOCATED IN KENTUCKY TO PJM INTERCONNECTION, L.L.C. PURSUANT TO KRS 278.218	)	CASE NO. 2002-00475

* * * * * * * *

PETITION FOR CONFIDENTIAL TREATMENT

Kentucky Power Company d/b/a American Electric Power ("Kentucky Power") moves the Commission pursuant to 807 KAR 5:001, Section 7, for an Order granting confidential treatment to page 3 of Kentucky Power's Response to Information Request 14 as set forth in the Commission's Order dated January 22, 2004. In support thereof Kentucky Power states:

The Request and Background.

Information Request 14(b) requires Kentucky Power to file and disclose:

> b. Provide a narrative description along with supporting work papers, calculations, etc., that demonstrate the differences between recent AEP forced outage rates and longer-term forced outage statistics for PJM as a whole, which PJM reserve margins take into account.

Page 3 of Kentucky Power's Response to Commission Data Request 14 includes information concerning forced outages of AEP's units. Kentucky Power does not object to providing the information to the Commission, subject to an order according it confidential treatment.

If required to disclose publicly the information contained on page 3 of Kentucky Power's Response to Staff Information Request 14(b), Kentucky Power's negotiating position in making off-system sales will be affected adversely. Specifically, information concerning forced outages would aid persons purchasing power from AEP to calculate AEP's cost of generating the power and hence the "floor" at which AEP could sell the power. The public availability of this information could harm AEP's position in the marketplace and reduce AEP's ability to make off-system sales which in turn would reduce the benefits that flow to Kentucky ratepayers via the System Sales tracker.

KRS 61.878(c)(1)(b) excludes from the Open Records Act:

> "Records confidentially disclosed to an agency, generally recognized as confidential or proprietary, which if openly disclosed would present an unfair commercial advantage to competitors of the entity that disclosed the records, and which are compiled and maintained . . . in conjunction with the regulation of commercial enterprise . . ."

This exception applies to page 3 of Kentucky Power's Response to Information Request 14(b).

The Information Is Generally Recognized As Confidential and Proprietary.

First, the records to be filed with the Commission are "generally recognized as confidential or proprietary." The forced outage information is highly confidential,[1] and its confidentiality is critical to ability of AEP to participate in the off system sales market. Dissemination of the requested information is restricted by Kentucky Power and the Company takes all reasonable measures to prevent its disclosure to the public as well as persons within the Company who do not have a need for the information.

[1] A limited amount of the information as it pertains only to Kentucky Power's Big Sandy units is filed with the Commission in connection with the Commission's statutory review of Kentucky Power's Fuel Adjustment Clause. The informantion on page 3 provides outage information in a different format concerning all of AEP's units. The information concerning units other than Big Sandy is not made public.

Disclosure Of The Information Will Result In An Unfair Commercial Advantage.

For the reasons set forth above, disclosure of the confidential information also will result in an unfair commercial advantage to competitors of Kentucky Power and to which it and AEP make off-system sales.

The Information Is Compiled And Maintained In Conjunction With The Commission's Regulation of Kentucky Power.

Finally, the records requested in Information Request 14(b) are compiled and maintained "in conjunction with the regulation of a commercial enterprise." Kentucky Power acknowledges that information concerning forced outages is subject to Commission review. Any filing, however, should be subject to a confidentiality Order and the parties to this proceeding should negotiate a confidentiality agreement. If such an agreement cannot be agreed to, the information should be subject to a Protective Order issued pursuant to 807 KAR 5:001, Section 7(5)(b).

In further support of this Motion for Confidential Treatment, Kentucky Power notes this information has been accorded confidential treatment by the Federal Energy Regulatory Commission.

Respectfully submitted,

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COUNSEL FOR KENTUCKY POWER
COMPANY D/B/A AMERICAN ELECTRIC
POWER

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by first class mail, postage prepaid, upon the following parties of record, this 5th day of February, 2004.

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Mark R. Overstreet

KE057:KE157:10495:1:FRANKFORT

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY)
d/b/a AMERICAN ELECTRIC POWER, FOR)
APPROVAL, TO THE EXTENT NECESSARY,)
TO TRANSFER FUNCTIONAL CONTROL OF)CASE NO. 2002-00475
TRANSMISSION FACILITIES LOCATED IN)
KENTUCKY TO PJM INTERCONNECTION, L.L.C.)
PURSUANT TO KRS 278.218)

RESPONSE OF KENTUCKY POWER COMPANY
D/B/A
AMERICAN ELECTRIC POWER

COMMISSION SUPPLEMENTAL DATA REQUESTS

February 5, 2004

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 4 of the Direct Testimony and Exhibits on Rehearing of J. Craig Baker ("Baker Testimony"), lines 11-15.

Provide a copy of the Federal Energy Regulatory Commission ("FERC") order referenced.

RESPONSE

Copies of the FERC Orders are attached.

WITNESS: J. Craig Baker

UNITED STATES OF AMERICA105 FERC ¶ 61,212
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, and Nora Mead Brownell.

Midwest Independent Transmission System Operator	Docket Nos. EL02-111-004 EL02-111-005 EL02-111-006 EL02-111-007 EL02-111-008

PJM Interconnection, L.L.C.

and all Transmission Owners
(including the entities identified below)

Union Electric Company

Central Illinois Public Service Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Kingsport Power Company

Ohio Power Company

Wheeling Power Company

Michigan Electric Transmission Company

Dayton Power and Light Company

Commonwealth Edison Company

Commonwealth Edison Company
of Indiana, Inc.

American Transmission Systems, Inc.

Illinois Power Company
Northern Indiana Public Service Company

Virginia Electric and Power Company

IES Utilities, Inc.

Interstate Power Company

Aquila, Inc. (formerly UtiliCorp United, Inc.)

PSI Energy, Inc.

Union Light Heat & Power Company

Dairyland Power Cooperative

Great River Energy

Hoosier Energy Rural Electric Cooperative

Indiana Municipal Power Agency

Indianapolis Power & Light Company

Louisville Gas & Electric Company

Kentucky Utilities Company

Lincoln Electric (Neb.) System

Minnesota Power, Inc. and its subsidiary
Superior Water, Light & Power Company

Montana-Dakota Utilities

Northwestern Wisconsin Electric Company

Otter Tail Power Company

Southern Illinois Power Cooperative

Southern Indiana Gas & Electric Cooperative

Southern Minnesota Municipal Power Agency

Sunflower Electric Power Corporation

Wabash Valley Power Association, Inc.

Wolverine Power Supply Cooperative

International Transmission Company

Alliant Energy West

Xcel Energy Services, Inc.

MidAmerican Energy Company

Corn Belt Power Corporation

Allegheny Electric Cooperative, Inc.

Atlantic City Electric Company

Baltimore Gas & Electric Company

Delmarva Power & Light Company

Jersey Central Power & Light Company

Metropolitan Edison Company

PECO Energy Company

Pennsylvania Electric Company

PPL Electric Utilities Corporation

Potomac Electric Power Company

UGI Utilities, Inc.

Allegheny Power

Carolina Power & Light Company
Central Power & Light Company

Conectiv

Detroit Edison Company

Duke Power Company

GPU Energy

Northeast Utilities Service Company

Old Dominion Electric Cooperative

Public Service Company of Colorado

Public Service Electric & Gas Company

Public Service Company of Oklahoma

Rockland Electric Company

South Carolina Electric & Gas Company

Southwestern Electric Power Company

Cincinnati Gas & Electric Company

Missouri Public Service

WestPlains Energy

Cleco Corporation

Kansas Power & Light Company

OG+E Electric Services

Southwestern Public Service Company

Empire District Electric Company

Western Resources
Kansas Gas & Electric Co.

Ameren Services Company on behalf of: Union Electric Company Central Illinois Public Service Company	Docket No. EL03-212-002

American Electric Power Service Corporation
On behalf of:
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Kingsport Power Company
Ohio Power Company
Wheeling Power Company

Dayton Power and Light Company

Exelon Corporation
On behalf of:
Commonwealth Edison Company
Commonwealth Edison Company
of Indiana, Inc.

FirstEnergy Corporation
On behalf of:
American Transmission Systems, Inc.

Illinois Power Company

Northern Indiana Public Service Company

American Electric Power Service Corporation On behalf of: Appalachian Power Company Columbus Southern Power Company Indiana Michigan Power Company Kentucky Power Company Kingsport Power Company Ohio Power Company Wheeling Power Company Commonwealth Edison Company Commonwealth Edison Company of Indiana, Inc. The Dayton Power and Light Company v. Midwest Independent Transmission System Operator, Inc.	Docket No.	EL04-4-000
American Electric Power Service Corp., et al. Commonwealth Edison Co. Commonwealth Edison Company of Indiana, Inc. Dayton Power and Light, Co. v. PJM Interconnection, LLC	Docket No.	EL04-5-000
American Electric Power Service Corp., et al. Commonwealth Edison Co. Commonwealth Edison Company of Indiana, Inc. Dayton Power and Light, Co. v. Ameren Services Co.	Docket No.	EL04-6-000
American Electric Power Service Corp., et al. Commonwealth Edison Co. Commonwealth Edison Company of Indiana, Inc. Dayton Power and Light, Co. v. Illinois Power Co.	Docket No.	EL04-7-000
American Electric Power Service Corp., et al. Commonwealth Edison Co. Commonwealth Edison Company of Indiana, Inc. v. Dayton Power and Light, Co.	Docket No.	EL04-8-000

American Electric Power Service Corp., et al. Docket No. EL04-9-000
Dayton Power and Light, Co.
v.
Commonwealth Edison Co.
Commonwealth Edison Company of Indiana, Inc.

Commonwealth Edison Co. Docket No. EL04-10-000
Commonwealth Edison Company of Indiana, Inc.
Dayton Power and Light, Co.
v.
American Electric Power Service Corp., et al

ORDER DENYING REHEARING IN PART AND GRANTING REHEARING IN PART, DIRECTING COMPLIANCE FILINGS, AND DISMISSING COMPLIANCE FILINGS AND COMPLAINTS

(Issued November 17, 2003)

1. In this order, we grant in part, and deny in part, requests for rehearing of the July 23 Order[1] that pertain to Docket No. EL02-111. We also make findings with respect to a new rate design for regional through and out service and direct compliance filings to implement that rate design effective April 1, 2004. This order benefits customers by ensuring that the design of rates of regional transmission organizations (RTOs) promotes efficient and competitive electricity markets in accordance with the requirements of Order No. 2000.[2]

[1] Midwest Independent Transmission System Operator, et al., 104 FERC ¶ 61,105 (2003) (July 23 Order).

[2] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 & 31,089 at 31,086 (1999), order on reh=g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 & 31,092 (2000), aff'd sub nom. Public Utility District No. 1 of Snohomish County Washington, et al. v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

I. Background

2. In the Initial Decision in Docket No. EL02-111-000,[3] the Presiding Judge determined that there was a lack of precedential authority that would permit him to eliminate the Regional Through and Out Rates (RTORs)[4] for transactions between the expanded Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and expanded PJM Interconnection, L.L.C. (PJM) under the circumstances of that proceeding. The Presiding Judge added that if, in a change of policy, the Commission was to order it, he would recommend that the Commission adopt, without requiring the filing of new rate cases, a transitional lost revenue recovery mechanism such as one of the Seams Elimination Charge/Cost Adjustment/Assignment (SECA) proposals submitted by the parties to prevent cost shifting.

3. In the July 23 Order, the Commission disagreed with the Presiding Judge's finding that there was a lack of precedential authority to eliminate the RTORs between the expanded Midwest ISO and expanded PJM under the circumstances of the case, and concluded that the Midwest ISO and PJM RTORs, when applied to transactions sinking within the proposed Midwest ISO/PJM footprint, are unjust and unreasonable. The Commission directed PJM and Midwest ISO to make a compliance filing within 30 days eliminating the RTORs for such transactions, effective November 1, 2003.[5] The Commission declined to fix a transitional lost revenue recovery mechanism to replace the eliminated rates, but provided guidance regarding such mechanisms and invited parties to

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[3] Midwest Independent Transmission System Operator, Inc., et al., 102 FERC ¶ 63,049 (2003) (Initial Decision).

[4] We define the Midwest ISO RTOR as the single, system-wide transmission rate in Schedules 7 and 8, and the Schedule 14 Regional Through and Out Rate. For PJM, the RTOR is the single, system-wide transmission rate for delivery to the PJM Border in Schedules 7 and 8 and the Transitional Revenue Neutrality Charge (TRNC).

[5] On August 22, 2003, PJM and Midwest ISO filed compliance filings in Docket Nos. EL02-111-005 and EL02-111-006 containing revisions to their respective Open Access Transmission Tariffs (OATTs) that provide for the elimination of their RTORs, in accordance with the July 23 Order. On October 17, 2003, in Docket No. EL02-111-008, Midwest ISO submitted an additional compliance filing. As we are granting rehearing and directing further compliance filings in the instant order, these compliance filings are now moot. Therefore, we will dismiss these filings in this proceeding. For the same reason, we will also dismiss the regional SECA proposal and complaints filed by New PJM Cos. (AEP, ComEd and DP&L) in Docket Nos. EL02-111-007, EL03-212-002, and EL03-4-000, et al.

file such mechanisms under Section 205 of the Federal Power Act (FPA).[6] The Commission also stated that, even with the elimination of the Midwest ISO and PJM RTORs, in the near term the region will still be riddled with seams, with the through and out (T&O) rates under the individual tariffs of certain former Alliances Companies[7] ("former Alliance Companies" or "Companies") acting as toll gates that impede the realization of more efficient and competitive electricity markets in the region and that preserve a competitive advantage for the non-RTO members' generation. Accordingly, the Commission established an investigation under Section 206 of the FPA[8] in Docket No. EL03-212-000 to determine whether the Companies' T&O rates should be eliminated.

II. Filings

4. American Municipal Power-Ohio, Inc. (AMP-Ohio), Cinergy Services, Inc. (Cinergy), Detroit Edison Company (Detroit Edison), GridAmerica Companies[9] (GridAmerica), the Michigan Agencies,[10] Multiple TDUs,[11] and Pennsylvania Public Utility Commission (Pennsylvania Commission) filed timely requests for rehearing. Midwest ISO filed a timely motion for clarification and New PJM Cos. and Midwest ISO Transmission Owners (Midwest ISO TOs) filed timely requests for rehearing and motions for clarification. Cinergy filed an answer to Midwest ISO's motion for clarification. The State of Michigan and the Michigan Public Service Commission

[6] 16 U.S.C. § 824d (2000).

[7] American Electric Power Service Corp. on behalf of Appalachian Power Co., Columbus Southern Power Co., Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co., and Wheeling Power Co. (collectively, AEP), Ameren Services Co. on behalf of Union Electric Co. and Central Illinois Public Service Co. (collectively, Ameren), Commonwealth Edison Co. on behalf of itself and Commonwealth Edison Co. of Indiana (collectively, ComEd), FirstEnergy Corp. on behalf of American Transmission Systems, Inc. (ATSI) (collectively, FirstEnergy), Illinois Power Co. (Illinois Power), Northern Indiana Public Service Co. (NIPSCO) and Dayton Power and Light Co. (DP&L).

[8] 16 U.S.C. § 824e (2000).

[9] The GridAmerica Companies are: Ameren, FirstEnergy, and NIPSCO.

[10] Michigan Public Power Agency and Michigan South Central Power Agency.

[11] Coalition of Municipal and Cooperative Users of New PJM Cos.' Transmission, Indiana Municipal Power Agency and Southeast Michigan Systems.

(collectively, Michigan Commission) filed a timely motion for clarification and alternatively, a request for rehearing to which GridAmerica filed an answer.

5. A number of parties contend that the Commission's elimination of Midwest ISO and PJM's RTORs violates the requirements of FPA Section 206. They claim that the Commission found the RTORs not just and reasonable based on such general policy grounds as economic efficiency and adequate RTO scope and configuration, but did not provide substantial evidence or make the required particularized findings to support eliminating the RTORs.[12] According to New PJM Cos., the Commission's evidence and findings, at best, might support a generic elimination of all rate pancaking, but such evidence cannot be relied upon to support the selective elimination of only Midwest ISO and PJM's RTORs, and then only for certain transactions. Some parties further argue that the Commission's finding is also contrary to Commission precedent and policy with some parties suggesting that the Commission's elimination of the RTORs departs from its prior approval of Midwest ISO and PJM as RTOs.[13] New PJM Cos. argue that the finding that their choices to join PJM result in unjust and unreasonable rates for transactions between Midwest ISO and PJM is at odds with the policy guidance regarding rate design and delegation of functions provided in the Commission's Order on Petition for a Declaratory Order, in which the Commission indicated that its policy guidance would apply whether the Alliance Companies joined PJM or Midwest ISO.[14] In addition, Certain Classic PJM TOs state that the Commission eliminated the RTORs in an attempt to remedy its prior approval of the expanded PJM and expanded Midwest ISO. They assert that the Commission should not have approved the scope of the expanded PJM unless the Companies had simultaneously submitted an acceptable plan to eliminate the seam between the expanded PJM and expanded Midwest ISO.[15]

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[12] See, e.g., Pennsylvania Commission Rehearing at 6-7; New PJM Cos. Rehearing at 9-12; Certain Classic PJM TOs at 10.

[13] See, e.g., New PJM Cos. Rehearing at 24-28 (citing Midwest Independent Transmission System Operator, et al, 97 FERC ¶ 61,326 (2001); PJM Interconnection, LLC, et al., 101 FERC ¶ 61,345 (2002)).

[14] See New PJM Cos. Rehearing at 22-23 (citing Alliance Cos., et al., 99 FERC ¶ 61, 105 (2002) (Order on Petition)).

[15] See Certain Classic PJM TOs Rehearing at 15-19. They also assert that the July 23 Order conflicts with Order No. 2000 and the SMD White Paper, which they argue do not require the elimination of border rates between RTOs. Id. at 16-21; see also New PJM Cos. Rehearing at 28.

6. Some parties also argue that the Commission failed to consider the impacts of eliminating the RTORs. Certain Classic PJM TOs state that cost shifts from Midwest ISO's native load to PJM's native load would result, thereby creating a discriminatory rate structure.[16] They also argue that eliminating the Midwest ISO and PJM RTORs discriminates against transmission-owning members of existing PJM and Midwest ISO because it would allow non-RTO participants to continue charging export fees.[17] They and New PJM Cos. support retaining the RTORs until the Midwest ISO and PJM joint and common market is formed, which New PJM Cos. assert would lead to the elimination of the RTORs.[18] Multiple TDUs recommend maintaining the RTORs for transactions to serve the bundled retail load of RTO non-participants, even while the Commission otherwise eliminates the RTORs and the non-participants' T&O rates.[19]

7. Certain parties also object to the November 1, 2003 date set by the July 23 Order as the effective date for the elimination of the RTORs without simultaneously replacing them with a lost revenue recovery mechanism.[20] Certain Classic PJM TOs add that the Commission has arbitrarily established this date for eliminating the RTORs because it has not conditioned the date on any of the New PJM Cos. actually joining PJM. It asserts that the Commission has moved prematurely to address alleged potential seams that may not arise due to the uncertainty as to whether any of the New PJM Cos. will be in an RTO by that time. However, Consumers Energy supports eliminating the RTORs on the earliest possible date, i.e., January 18, 2003.[21]

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[16] See Certain Classic PJM TOs Rehearing at 11 (citing Initial Decision at P 68-75).

[17] See Certain Classic PJM TOs Rehearing at 21-22.

[18] See New PJM Cos. Rehearing at 30; Certain Classic PJM TOs Rehearing at 14-15.

[19] Multiple TDUs state that unlike AEP, the RTOs and their non-former-Alliance-Company stakeholders are not late in meeting a merger commitment to join an RTO, and the transmission owners that are participating in one of the RTOs have not been enjoying the benefits of "market-independent and broadly [sic] regional planning, development, and operation of the former Alliance Companies' facilities." They suggest that if the RTORs are eliminated for transactions to serve the bundled load of RTO non-participants, this benefit should be credited against any non-participant's claim for recovery of lost revenues. See Multiple TDU's Conditional Request for Rehearing at 9.

[20] See, e.g., New PJM Cos. Rehearing at 33-34; Certain Classic PJM TOs at 12-13.

[21] See Consumers Energy Rehearing at 5-8.

III. Commission Response

A. Justness and Reasonableness of RTORs

8. We will deny rehearing of our finding that the Midwest ISO and PJM RTORs are not just and reasonable. Our finding in the July 23 Order that the RTORs are unjust and unreasonable for transactions sinking in the RTOs was based on reasonable factual determinations and policy considerations and was consistent with Commission precedent, and the parties have not convinced us otherwise. The July 23 Order is one of a series of Commission orders that document the problems of RTO scope and configuration in this region.[22] The July 23 Order explained how the RTO choices of certain of the former Alliance Companies would perpetuate these problems. Specifically, the July 23 Order cited evidence that these choices would divide a highly interconnected portion of the grid, leaving in place an elongated and irregular seam across which significant trading activity takes place, and would leave portions of Midwest ISO (Wisconsin and Michigan) only partially contiguous with the rest of Midwest ISO. These facts indicated that the proposed RTO configuration would divide a natural market, subjecting a significant number of transactions in the region to continued rate pancaking, and require companies in Wisconsin and Michigan to pay pancaked rates in order to wheel power through PJM from elsewhere in Midwest ISO.

9. On this basis, the Commission found that the RTORs, when applied to transactions sinking in the RTOs, would: (1) violate the fundamental requirement of Order No. 2000 that RTOs eliminate rate pancaking over a region of appropriate scope and configuration; (2) obstruct the realization of more efficient and competitive electricity markets in the region; and (3) result in unjust, unreasonable, and unduly discriminatory or preferential RTO rates. Accordingly, it concluded that a new rate design must be established for such service. The new rate design would be established in two steps. Initially, as discussed below, a transitional rate design would be implemented and remain in effect for a two-year period.[23] The transitional rate design is based on the existing just and reasonable rates and revenues for regional through and out service, but will recover these revenues from customers, in proportion to the benefits that such customers will receive from the

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[22] See, e.g., Alliance Companies, et al., 103 FERC ¶ 61,274 at P 26-28 (2003) (June 4 Order); Alliance Companies, et al., 100 FERC ¶ 61,137 (2002); PJM Interconnection, L.L.C., et al., 96 FERC ¶ 61,061 (2001), order on reh'g, 101 FERC ¶ 61,345 (2002); Midwest Independent Transmission System Operator, Inc., 97 FERC ¶ 61,326 at 62,507-08, order on reh'g, 103 FERC ¶ 61,169 (2001).

[23] As we explain below, we set a new effective date of April 1, 2004 to implement the new rate design for such services.

elimination of the unjust and unreasonable rate design in the region, through a non-bypassable surcharge for delivery to load. Further, as we discuss below, the transitional rate design will only apply to new transactions commencing on or after the effective date; for existing transactions, we will allow the existing RTOR rate design to remain in effect during the transition period. The transitional rate design will eliminate the injurious effects on efficient use of the grid associated with rate pancaking, while maintaining the cost responsibility and revenue flows under the existing RTORs, thus mitigating cost shifting among customers and revenue losses that would otherwise occur if rate pancaking were eliminated without a transitional rate mechanism. This will allow time for the parties to develop a long-term rate design solution that efficiently prices transmission service between the two RTOs to take effect at the end of the transition period.

10. Further, we disagree with Certain Classic PJM TOs that the July 23 Order departed from our orders approving Midwest ISO and PJM as RTOs. In those orders, we conditioned our approval of these RTOs based on their attaining sufficient scope to satisfy Order No. 2000. The Commission granted Midwest ISO RTO status based on its finding that Midwest ISO was best positioned to meet the requirements of Order No. 2000; however, it specifically noted that Midwest ISO's configuration problems on its eastern border were inconsistent with Order No. 2000's scope and configuration requirements, and found that these problems could be solved by successful integration of some or all of the Alliance Companies into Midwest ISO.[24]

11. Similarly, in the Commission's initial order on PJM's RTO proposal, the Commission found that PJM exhibited insufficient scope to meet the requirements of Order No. 2000 and encouraged PJM to continue its efforts to expand in the region. On rehearing, the Commission found that PJM's planned expansion to incorporate some of the former Alliance Companies alleviated concerns regarding the possible insufficient scope of PJM as an RTO.[25] These actions are consistent with Order No. 2000, which specifically provided that the Commission would not categorically deny RTO status or delay RTO start-up where transmission owners representing a large majority of the facilities in a region are ready to move forward, even though agreement by a few transmission owners in the region has yet to be determined.[26]

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[24] Midwest Independent Transmission System Operator, Inc., 97 FERC ¶ 61,326 at 62,507-508, order on reh'g, 103 FERC ¶ 61,169 (2001).

[25] See PJM Interconnection, L.L.C., et al., 96 FERC ¶ 61,061 (2001), order on reh'g, 101 FERC ¶ 61,345 (2002).

[26] See Order No. 2000 at 31, 086.

12. We also disagree with New PJM Cos. that the July 23 Order is inconsistent with the Order on Petition. While the Commission indicated that the guidance it gave in the Order on Petition would apply whether the Alliance Companies joined PJM or Midwest ISO, the Commission intended that the resulting choices would continue to be evaluated against the scope and configuration requirements of Order No. 2000. In this regard, the Commission was acting consistent with Order No. 2000's receptivity to flexible and innovative ways to achieve appropriate RTO scope and configuration, such as the use of inter-RTO coordination to eliminate seams.[27] The Commission exercised this flexibility in establishing the conditions for New PJM Cos.' participation in PJM, including the requirement for a solution to inter-RTO rate pancaking.[28]

13. Here, our actions continue to be consistent with Order No. 2000 as our finding that the Midwest ISO and PJM RTORs are unjust and unreasonable is another step towards ensuring that Midwest ISO and PJM achieve appropriate scope and configuration. Our actions are also consistent with the SMD NOPR and White Paper, as discussed in the July 23 Order.[29]

14. As to the scope of the elimination of the RTORs, we will eliminate the RTORs for new transactions sinking in the combined region (i.e., Midwest ISO, PJM and the Companies' footprints).[30] The July 23 Order eliminated the RTORs with respect to transactions serving load in PJM and Midwest ISO. We clarify our intent in the July 23 Order to eliminate the RTORs for transactions sinking in the RTO non-participants' systems if the T&O rates under their individual-company Open Access Transmission Tariffs (OATTs) were eliminated in the July 23 Order's new Section 206 investigation into the justness and reasonableness of certain former Alliance Companies' T&O rates. As our companion order in Docket No. EL03-212-000, being issued concurrently with this order, directs the elimination of the T&O rates under the individual-company tariffs for transactions sinking in the region, we clarify that the RTORs are also eliminated for transactions sinking in the Companies' systems. In that order, we are not eliminating the T&O rates with respect to existing transactions (i.e., those existing as of the effective date) during the two-year transition period since

[27] Id. at 31,083.

[28] See June 4 Order, 103 FERC at P 31.

[29] See July 23 Order, 104 FERC at P 36.

[30] As also clarified in our Companion Order, the proposed Midwest ISO/PJM footprint as discussed in the July 23 Order constitutes the combined footprints of Midwest ISO, PJM, and the Companies and shall henceforth be referred to as the "combined region".

efficiencies could only be produced after rate pancaking is eliminated, and thus, no new gains in efficiency would be realized for existing transactions.[31] Eliminating the RTORs only for new transactions during the transition period will minimize the lost revenues to be recovered through the lost revenue recovery mechanism. Therefore, consistent with our action in Docket No. EL03-212, we will not eliminate the RTORs for existing transactions that sink in the combined region, i.e., those existing prior to April 1, 2004, during the transition period.[32] In addition, we will deny Multiple TDUs' request to retain the RTORs for transactions serving the bundled load of the RTO non-participants, as this would perpetuate significant market inefficiencies.[33]

15. Further, we will change the effective date for the elimination of the RTORs for transactions sinking in the combined region from November 1, 2003 to April 1, 2004, to occur simultaneously with our elimination of the T&O rates of certain of the former Alliance Companies in our companion order in Docket No. EL03-212-000.[34] This new date will allow time to implement the replacement lost revenue recovery rates adopted here and in Docket No. EL03-212-000, to take effect simultaneously with the elimination of the RTORs. The details of the lost revenue recovery mechanism are explained in the next section. In addition, in order to quickly realize more efficient and competitive electricity markets in the combined region, we will not wait until the formation of the PJM/Midwest ISO common market to eliminate these rates since we can address the inter-RTO rate issue sooner than the planned October 2004 formation of the common market.

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[31] See July 23 Order at P 55 (Affirming the Presiding Judge's explanation that "efficiencies could only be produced by eliminating rate pancaking after the Commission issues a final order since past behavior cannot be changed.) For the same reason, we affirm our decision to not order refunds here as Consumers Energy requests. The July 23 Order also affirmed the Presiding Judge's ruling that no refunds should be ordered because the SECA replaces the RTORs with charges of a different form, a non-bypassable surcharge to be added to existing license plate zonal transmission rates but in approximately the same magnitude and imposed on the same groups of ratepayers; customers are not entitled to refunds because they have not overpaid.

[32] The RTORs are eliminated once the transition period ends.

[33] See Multiple TDUs' Conditional Request for Rehearing at 9.

[34] This addresses Certain Classic PJM TOs' concern that such elimination will discriminate against transmission owners of the existing PJM and Midwest ISO by allowing RTO non-participants to continue charging export fees. See Certain Classic PJM TOs Rehearing at 21-22.

16. We base our decision, in part, on the benefits of establishing a more efficient and competitive electricity market that would directly result from the elimination of the seams in the combined region, and, in part, on enforcing the requirements of Order No. 2000. Our action here brings the combined region closer towards eliminating the obstacles to the formation of efficient and competitive electricity markets and fulfilling the goals of Order No. 2000.

B. SECA Issue

Proposed SECAs

17. Two SECA proposals were sponsored by parties to the proceeding, one by GridAmerica and one by the Midwest ISO TOs, to prevent cost shifting between customers.[35] The SECAs are generally designed as non-bypassable surcharges to license plate zonal rates for delivery to load within the RTOs. The SECA proposals would charge the load in the importing RTO for transmission service taken over the transmission facilities of the exporting RTO in proportion to the benefits that load within the importing RTO will realize when it no longer pays pancaked rates for transmission service over the transmission facilities in the exporting RTO. The SECA revenues would be distributed to the exporting RTO to offset the exporting RTO's cost of providing such through and out service. The load in the importing RTO would pay approximately the same amount in the aggregate through the SECA surcharge as it had previously paid through the RTORs. However, the surcharges would be assessed on all deliveries by customers within the importing RTO, not only the through and out transactions, thereby avoiding the harmful effects on economic choices caused by customers having to pay multiple charges under the existing rate design. Transactions under grandfathered agreements and transactions that sink outside the combined region are not included in these calculations. North American Electric Reliability Council (NERC) tag data would be used to identify the loads benefiting from particular through and out transactions, and lost through and out service revenues would be assigned to loads on the basis of such analysis.

18. In the July 23 Order, the Commission found that it need not establish a mechanism for recovery of lost RTOR revenues in this proceeding and did not make any further findings regarding the Presiding Judge's recommendations or parties' concerns with the SECA. Rather, it required parties to make filings under Section 205 of the FPA to propose SECAs to recover lost RTOR revenues and to address the specific attributes of

[35] The Grid America and the Midwest ISO TOs' proposals are generally the same. However, Midwest ISO TOs propose to use 2001 NERC tag data instead of 2002 data, phase-out the SECA over three years, and allow Michigan and Wisconsin entities to opt-out of the SECA and continue paying the RTOR.

the SECA. As discussed below, we will grant rehearing on this issue and make findings with respect to appropriate transitional lost revenue recovery mechanisms that result in a change in rate design but not a change in the level of revenues. Instead of requiring Section 205 filings, we will direct compliance filings that will change rate design from the existing transaction-based charge to include transitional surcharges to take effect on April 1, 2004. In order to put their positions in proper perspective, we will discuss the Presiding Judge's decision, the parties positions in their briefs, the Commission's decision in the July 23 Order and the parties' requests for rehearing, before we discuss our decision here.

a. Presiding Judge's Ruling

19. In the Initial Decision, the Presiding Judge stated that if the Commission eliminates the RTORs of PJM and Midwest ISO, he would recommend that the Commission adopt a transitional rate mechanism like one of the proposed SECAs to prevent cost shifting between customers of the two RTOs. He reasoned that absent a SECA, the exporting RTO's native load would have to pay increased transmission rates because the revenue credits for through and out service would cease[36] and the importing RTO's native load would save money by not paying the RTORs for imports, resulting in a cost shift from the exporting RTO to the importing RTO.

20. The Presiding Judge stated that an updated cost-of-service is unnecessary to adopt a SECA because the SECA is designed to recover the same amount of revenues lost from the elimination of through and out charges from the same group of customers that had previously paid them, instead of from native load to whom that obligation would otherwise shift. The Presiding Judge also noted that the Midwest ISO TOs utilize a formula rate that would automatically adjust charges to native load upon the elimination of the RTORs unless a SECA mechanism is adopted to prevent such cost shifts.

21. The Presiding Judge also dismissed claims that the SECA violates the rule against retroactive rate making, reasoning that the SECA surcharges are not designed to recoup past losses but to recover future ones.[37] Nor, he found, would transmission owners

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[36] Through and out revenues are credited against the transmission owners' revenue requirements and relieve native load customers of responsibility for a portion of the transmission owners' cost-of-service in the basic transmission rates charged them by the transmission owners.

[37] The Presiding Judge added that the SECA revenues would take the place of lawful revenues that would otherwise be expected in the future if through and out charges were not eliminated. The Presiding Judge explained that it was only their calculation that

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recover more than they would have received had they continued to charge through and out rates. The Presiding Judge stated that it was only the form of revenue recovery that would change to insure that, in the event the through and out charges were eliminated, there would not be any cost shifting between the native loads of the two RTOs. He concluded that there would be no increase in rates, but only a change in their form.[38]

b. Briefs on Exceptions

22. Several parties opposed the Presiding Judge's recommendation that a SECA should replace the existing RTORs in the event that the Commission finds the RTORs unjust and unreasonable.[39] Generally, these parties raise concerns with respect to cost-shifting, consistency with traditional ratemaking principles, potential over-recovery of transmission owners' cost-of-service, and problems with implementation of the SECA in the Classic PJM territory.

23. Several parties argued that the Presiding Judge failed to recognize the cost shifting that will occur between generators and load as a result of implementing a SECA.[40] According to these parties, suppliers often paid charges for through and out service while the SECAs would recover all lost revenues only from load. They argued that the Commission specifically recognized this possibility when it set a similar transition rate

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was based on a past test period, as was almost every rate sanctioned by the Commission and the courts. He further explained that even their magnitude would not be set on the basis of past lost revenues, although the rates would be; rather, their magnitude would be determined based on the level of future transactions, to which those rates would be applied, no differently than is the case with other lawful rates and charges. Initial Decision at P 90.

[38] See Initial Decision at P 89.

[39] The following parties all oppose any type of SECA or other revenue recovery mechanism: JCA, Consumers, Michigan Agencies, Michigan Commission, Wisconsin Commission, Maryland Public Service Commission and Pennsylvania Public Utility Commission (Maryland and Pennsylvania Commissions), WEPCO, WPSC/UPPC, TRRG.

[40] See Initial Decision at P 75-77.

mechanism for hearing in Docket No. ER03-262-000.[41] They argued that there is no guarantee that these generators will pass on any cost savings to customers and that, therefore, cost shifting may result from the implementation of the SECA. TRRG stated that a cost-based approach to mitigating cost-shifts and eliminating rate pancaking, namely license plate rates with no lost revenue adders, has been used previously by other RTOs, including PJM.[42] It suggested that, given the intertwined nature of PJM and Midwest ISO, the Commission should view elimination of the RTORs as involving the elimination of intra-regional rate pancaking, and follow those cases.[43]

24. TRRG stated that any new load that appears in a zone will pay a SECA regardless of whether it was an importer of power during the test year, which, it argues, is in clear violation of cost causation principles.[44] Additionally, parties contended that the lost revenue recovery proposals will lead to retroactive rate increases when implemented because customers were not given notice before the test period that their transactions in the test period would form the basis for charges in subsequent years.[45]

25. Some parties argued that revenues related to through and out transactions are not fixed or obligatory and the loss of that revenue, whether through changes in market conditions or through a regulatory mandate, is not an inappropriate cost shift.[46] They believed that transmission owners are entitled to receive their expenses and a fair rate of return but are not entitled to a specific amount of such revenue.

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[41] See American Electric Power Service Corporation, 103 FERC & 61,008 (2003). This case involved a proposal to address lost revenue recovery and potential cost shifting due to the elimination of rate pancaking within the expanded PJM, when the New PJM Companies are integrated into PJM.

[42] TRRG also claims that lost revenue recovery mechanisms are unnecessary as incentives to participate in a RTO because of all the other incentive at the Commission's disposal and that such mechanisms could actually be an incentive to others that have yet to join a RTO to join an improperly configured one in order to collect the SECA.

[43] See TRRG Brief on Exceptions at 46.

[44] See TRRG Brief on Exceptions at 21-22.

[45] See, e.g., WI Commission Brief on Exceptions at 7-8. WEPCO Brief on Exceptions at 7 citing City of Piqua v. FERC, 610 F.2d 950, 954 (D.C. Cir. 1979), and Columbia Gas Transmission Co. v. FERC, 831 F.2d 1135, 1140 (D.C. Cir. 1987); TRRG Brief on Exceptions at 34.

[46] See, e.g., Michigan Agencies Brief on Exceptions at 15; Michigan Commission Brief on Exceptions at 14; TRRG Brief on Exceptions at 11.

26. Several parties raised the concern that a SECA will present an opportunity for transmission owners to over-recover their lost revenue amounts.[47] They objected to the Initial Decision's finding that the proposed SECAs would not collect from ratepayers amounts greater than the existing RTORs. They asserted that shareholder interests should be balanced against ratepayer interests. For example, Consumers noted that the proposed SECAs are fixed rates based on a historical test year, and, as load growth occurs, the SECA would over collect the test-year through and out revenues.[48] Some parties suggested that in adopting a lost revenue recovery mechanism, the Commission should look at the level of through and out revenues reflected in each transmission owner's most recent rate case to determine the level of through and out revenues it should be allowed to collect through the SECA, rather than basing it on revenues subsequently received through those rates.[49]

27. Other parties argued that the Commission must require the filing of a full rate case for each company to ensure that there is no over-recovery of its cost-of-service.[50] Some parties also expressed concern about the effect of a SECA in light of existing retail rate caps. For example, Classic PJM Companies and Midwest ISO TOs objected to the Presiding Judge's suggestion that the issue of potential inappropriate cost shifting to transmission owners as a result of retail rate caps is a problem that should be addressed only at the state level.[51] Midwest ISO TOs supported the inclusion of an opportunity for the creation of a regulatory asset account for portions of the SECA charges that are trapped because of retail rate freezes and caps. Conversely, WPSC/UPPC argued that the Commission should not allow the existence of retail rate caps or their potential impact on transmission owners throughout the combined PJM/MISO footprint to impact the design of a SECA.

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[47] See, e.g., Maryland and Pennsylvania Commissions Brief on Exceptions at 18, Consumers Brief on Exceptions at 38, JCA Brief on Exceptions at 18 and TRRG Brief on Exceptions at 40-42.

[48] See, e.g., Consumers Brief on Exceptions at 38.

[49] See JCA Brief on Exceptions at 21.

[50] For example, TRRG contends that other costs may have offset the loss in revenues due to the elimination of rate pancaking. TRRG Brief on Exceptions at 19. See also WEPCO Brief on Exceptions at 27.

[51] See Classic PJM Companies Brief on Exceptions at 17-18, Midwest ISO TOs Brief on Exceptions at 29.

28. With respect to the implementation of the SECA, some parties asserted that it is impossible to appropriately implement a SECA within the Classic PJM region.[52] They noted that, because the Classic PJM region operates as a single control area, the NERC tag data used to identify the loads benefiting from particular through and out transactions will simply indicate the entire PJM control area as the sink but will not reveal the location of the load within PJM served through that transaction. Therefore, they argued, there is no way to accurately trace the benefits of eliminating through and out rates to those who historically imported power.

29. Finally, the Ohio Commission and TRRG argued that customers should receive financial transmission rights in exchange for any lost revenues for which they are made responsible through implementation of a SECA.[53] TRRG argued that such treatment would accord with the fact that customers received firm rights associated with the through and out service that they paid for prior to the elimination of rate pancaking. Otherwise, they asserted, customers would be denied the benefits of RTO formation as envisioned by the Commission.

c. Briefs Opposing Exceptions

30. A number of parties supported the Presiding Judge's ruling that a lost revenue recovery mechanism should be put in place simultaneously with the elimination of rate pancaking.[54] While the parties who supported the Presiding Judge's adoption of the SECA had differing opinions concerning certain attributes of the SECA, as discussed more fully below, they generally agreed that the Commission should approve the SECA.[55]

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[52] See, e.g., JCA Brief on Exceptions at 15, Classic PJM Companies Brief on Exceptions at 12, TRRG Brief on Exceptions at 62.

[53] See Ohio Commission Brief on Exceptions at 9, TRRG Brief on Exceptions at 70-71.

[54] See, e.g., Briefs Opposing Exceptions filed by New PJM Companies, GridAmerica, Ormet, Trial Staff, Illinois Power, and Midwest ISO TOs.

[55] Trial Staff believes the evaluation of the SECA proposal requires that the nature and principles underlying the computation of the SECA be clear, and that there be a reasonable approximation of the impacts on both the transmission owners and LSEs from the complete elimination of through and out rates for transactions between the RTOs, as the Midwest ISO TOs provided. Trial Staff Brief on Exceptions at 13.

31. The parties supported adopting the SECA because it allows for lost revenue recovery and thereby mitigates cost shifting associated with the elimination of rate pancaking.[56] They claimed that a SECA-type mechanism is a just and reasonable replacement for the RTORs.[57] Trial Staff noted that a SECA mechanism will not protect against all cost shifting, but argued that it is administratively feasible and a good method of maintaining revenue neutrality and controlling cost-shifting due to the elimination of rate pancaking.[58] Further, GridAmerica contested the arguments that the SECA would shift costs from generators to load, stating that there is no record evidence demonstrating that there are a substantial number of transactions in the combined region where generators pay the RTOR. GridAmerica argued, where generators do pay the RTOR, removing the RTOR lowers the generator' cost which should be reflected in lower prices for power to load.[59] Moreover, Ormet, a transmission customer of AEP, noted that AEP receives a significant amount of revenue from through and out transactions, and elimination of these pancaked charges without a replacement SECA-type mechanism would result in considerable zonal rate increases, thus resulting in inequitable cost shifting. Ormet states that, although it ultimately believes that a single system rate should be adopted as a long term solution, it is in support of a SECA-type mechanism as a transitional solution to address the cost shifting problem from eliminating pancaking.[60]

32. Several parties[61] argued that the SECA is just and reasonable and consistent with Commission precedent because it is calculated in a manner similar to the rate design that the Commission previously accepted.[62] For example, GridAmerica cited to precedent where the Commission has found surcharges which assign lost revenue responsibility proportional to the benefits received from the elimination of rate pancaking to be

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[56] See, e.g., Illinois Power Brief Opposing Exceptions at 6-11.

[57] See, e.g., New PJM Cos. Brief Opposing Exceptions at 26, GridAmerica Brief Opposing Exceptions at 16, Illinois Power Brief Opposing Exceptions at 5, Trial Staff Brief Opposing Exceptions at 17.

[58] See Trial Staff Brief Opposing Exceptions at 17-18; See also GridAmerica Brief Opposing Exceptions at 16-17.

[59] GridAmerica Brief Opposing Exceptions at 14-15.

[60] See Ormet Brief Opposing Exceptions at 4-6.

[61] See e.g., New PJM Cos. Brief Opposing Exception at 35; GridAmerica Brief Opposing Exceptions at 11, 17; Midwest ISO TOs Brief Opposing Exceptions at 8; Illinois Power Brief Opposing Exceptions at 6, 11.

[62] See, e.g., Alliance Companies, 94 FERC & 61,070 (2001).

reasonable.[63] Additionally, Illinois Power cited to several other cases in which the Commission has approved a revenue neutrality charge.[64] Further, Illinois Power stated that Commission policy provides for non-native load transmission customers to have equal rights to use the transmission system and thus, an equal obligation to pay for the costs of such system.[65]

33. GridAmerica also argued that the SECA mechanism is not a form of retroactive ratemaking because it does not allow for recovery of past losses for past services but, rather, is based on the well-accepted practice of using a test period for determining rates for future service.[66] Trial Staff stated that SECA proposals must be based on a historical period because what is being preserved is the amount of revenues that the utility would have collected without the elimination of the seams charge.[67] Trial Staff argued that once the RTORs are eliminated, trading patterns could change, and basing the SECA charges on those trading patterns will not preserve the prior revenues.

34. New PJM Cos. objected to the argument that a SECA will lead to excessive recovery of transmission owners' revenue requirements. They noted that the rate analysis sponsored by TRRG, which was the core basis for its argument, was discredited at hearing.[68] In addition, New PJM Cos. and others asserted that transmission owners need

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[63] See GridAmerica Brief Opposing Exceptions at 11-12 citing Midwest Independent Transmission System Operator, Inc. 103 FERC ¶ 61,090 at P 15 (2003).

[64] See Illinois Power Brief Opposing Exceptions at 7 citing Avista Corp., et al., 100 FERC ¶ 61,274 (2002) (RTO West); Cleco Power LLC et al., 101 FERC ¶ 61,008 (2002) (SeTrans); Midwest Independent Transmission System Operator, Inc., 101 FERC ¶ 61,319 (2002). Illinois Power states that even though the lost revenues were recovered through a RTOR in the RTO West and SeTrans cases, the charges conform to the principles of revenue neutrality in that they are based on test period revenue collections, are collected as an addition to the otherwise applicable rate for a defined period of time, and are intended to be eliminated once a superseding rate design is implemented.

[65] See Illinois Power Brief Opposing Exceptions at 10.

[66] See GridAmerica Brief Opposing Exceptions at 17.

[67] See Trial Staff Brief Opposing Exceptions at 15.

[68] See New PJM Cos. Brief Opposing Exceptions at 38-41. For example, TRRG's witness used Attachment O to the Midwest ISO OATT even though that attachment is not used by PJM and has not been determined to be just and reasonable for companies in PJM. Further, after initial claims that most of the Companies had high earned rates of return, TRRG's witness adjusted his exhibits to show that many of the companies had

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not submit full cost and revenue analysis prior to recovering lost revenues,[69] arguing that requiring such filings would be inconsistent with established Commission precedent. [70] New PJM Cos. believe that this proceeding should be viewed in the proper context of a major industry restructuring. They argued that, because the creation of RTOs requires the elimination of some rates, and the restatement of others, the Commission has not required full rate cases for each change in rates engendered by the restructuring.

35. GridAmerica also responded to the arguments raised that a SECA mechanism is impractical to implement in the Classic PJM region, stating that this hurdle should not necessitate the denial of a SECA.[71] Rather, GridAmerica argued, PJM and the transmission owners in the Classic PJM region will have to make a more involved search or appropriate data or should be required to set forth an alternate allocation method in a compliance filing to the Commission.[72]

36. Some state commissions objected to the creation of regulatory asset accounts as a means to circumvent state retail rate caps. The Maryland Commission asserted that recovery of SECA costs should be resolved at the state level because of the complexity of

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earned returns of below 13 percent. TRRG's witness stated that other changes could be incorporated into his analysis that may reduce the earned rate of return even more. Another TRRG witness did not reflect the impact of several factors in his analysis and acknowledged that he made assumptions "that on closer scrutiny may not be absolutely valid."

[69] See, e.g., GridAmerica Brief Opposing Exceptions at 17-18; Commission Trial Staff Brief Opposing Exceptions at 21; Illinois Power Brief Opposing Exceptions at 14.

[70] New PJM Cos. cite Alliance Companies et al., 95 FERC ¶ 61,182 at 61,631 (2001) (clarifying that the Commission will not limit the lost revenue quantification to those revenues associated with cost levels last authorized in a federal or state rate case because doing so would be inconsistent with the concept of revenue neutrality); PJM Interconnection, LLC and Allegheny Power, 96 FERC ¶ 61,060 at 61,220 (2001) (denying requests that Allegheny be required to file an updated cost-of-service as inconsistent with the revenue neutrality concept).

[71] Illinois Power also addressed this issue, stating that the "problem is akin to a group of diners in a Chinese restaurant who, having shared plates delivered to the table, inform the waiter that since they do not have a record of who ate how much of what, they will be unable to pay the bill. No waiter worth his salt would accept such a glib response. Neither should the Commission." See Illinois Power Brief Opposing Exceptions at 16.

[72] GridAmerica Brief Opposing Exceptions at 14.

retail rate freezes. JCA asked the Commission to reject any argument or remedy that would circumvent state rate freezes.

37. Trial Staff stated that TRRG is incorrect for calling the SECA an incentive rate. Trial Staff believes that incentive rates are designed to provide efficiency incentives, whereas the SECA is a charge in substitution for existing rates and is intended to mitigate the adverse effects of joining a RTO. Illinois Power stated that to deny lost revenue recovery in this proceeding would act as a disincentive to other transmission owners joining RTOs.[73]

d. July 23 Order

38. The Commission stated that it is not obligated to establish a transitional rate mechanism to recover lost revenues due to the elimination of rate pancaking since it previously approved the elimination of rate pancaking without such mechanisms in cases where parties did not propose them or adequately support them. The Commission also stated that mechanisms such as the proposed SECAs, if properly structured, can serve as a reasonable transition mechanism to address revenue losses arising from the elimination of rate pancaking due to RTO formation. However, since the Commission found that it was not obligated to establish such mechanisms, it decided that, if the parties wanted a transitional rate mechanism, they would need to file under Section 205 of the FPA to establish it.

39. Consistent with our prior orders, the July 23 Order determined that it was not necessary for RTO members to file an updated cost-of-service to adopt a transitional rate mechanism, such as the SECA, as that may create an unnecessary impediment to RTO formation.[74] The Commission also affirmed the Presiding Judge that the evidence presented by parties in an attempt to demonstrate that the level of certain transmission owners' existing rates is excessive was faulty and did not convincingly show that the existing rates are unjust and unreasonable. The Commission reminded the parties that if they feel that the existing rates and revenues, upon which the transitional surcharges are based, are no longer just and reasonable, the complaint process under Section 206 of the FPA is available for them to seek a change in those rates and the corresponding surcharges.

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[73] Illinois Power Brief Opposing Exceptions at 10.

[74] The Commission did not address this issue for companies that are not RTO members.

e. **Rehearing Requests**

40. A number of parties contend that the Commission violated FPA Section 206 by finding the RTORs unjust and unreasonable without simultaneously establishing a replacement lost revenue recovery mechanism,[75] and that the Commission placed its burden of fixing a just and reasonable rate upon the utilities to make new rate filings under FPA Section 205. New PJM Cos. state that Commission policy requires consideration of the impact of lost revenues and cost shifting, and that the Commission should apply its policy favoring transitional rate mechanisms to mitigate potential revenue losses and cost shifts due to the elimination of rate pancaking. Midwest ISO TOs also state that the Commission's actions would deprive utilities of a reasonable opportunity to recover the costs of their facilities and would amount to an unlawful taking of this property without just compensation.[76] Some parties request that the Commission consider lost revenue recovery proposals in a second phase to the instant investigation if it does not reverse this finding and establish a lost revenue recovery mechanism based on the existing record.[77]

41. In addition, several parties argue that the FPA Section 205 filing option is inadequate, with Midwest ISO TOs and Cinergy expressing concern regarding how FPA Section 205 filings can be used to implement a typical lost revenue recovery mechanism.[78] Certain parties cite to the record in Docket No. EL02-111 as the basis for

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[75] See, e.g., Midwest ISO TOs Rehearing at 9-10; GridAmerica Rehearing at 9-12; Certain Classic PJM TOs at 10-11; New PJM Cos. Rehearing at 32-33. These parties support adoption of an effective date for elimination of the RTORs that is concurrent with the date that a replacement lost revenue recovery mechanism takes effect.

[76] See Midwest ISO TOs Rehearing at 11-15. They also contend that the Commission violated the previously accepted Midwest ISO Agreement by causing a major departure from revenue allocations assumed therein and requires Midwest ISO to violate its duty to maximize revenues associated with transmission service. Id. at 14-17.

[77] See, e.g., New PJM Cos. Rehearing at 32-33; Midwest ISO TOs Rehearing and Clarification at 9-10.

[78] They state that the lost revenue recovery mechanisms are designed to recover revenues lost from the elimination of the RTORs from the customers of another RTO, under whose tariff the entity seeking lost revenue recovery does not have FPA Section 205 filing rights. Midwest ISO TOs Rehearing at 27-30; Cinergy Rehearing at 6.

their support or opposition to the SECA mechanisms.[79] Certain parties also assert that, contrary to the July 23 Order's finding, there is sufficient record evidence to evaluate the SECA mechanisms introduced in Docket No. EL02-111-000.[80] Multiple TDUs assert that a specific rate proposal is needed before the Commission can make any final determinations regarding an appropriate methodology.[81] Some parties also claim that the Commission failed to address their reasons for objecting to the SECA mechanism, as stated in their briefs.[82] Detroit Edison requests that the Commission clarify whether companies not currently participating in a RTO are precluded from seeking recovery of lost revenues.[83] It and other parties seek rehearing of the Commission's determination that an updated cost-of-service would not be necessary to recover lost revenues for transmission owners that are already RTO members.[84] Detroit Edison asserts that the Commission has neither supported its decision not to require cost support for a transitional rate mechanism nor balanced investor and consumer interests.[85] Detroit Edison argues that it would be arbitrary to require an updated cost-of-service for non-participants, but not require an updated cost-of-service for RTO members.[86]

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[79]New PJM Cos. supports adoption of the SECA mechanism, with the exception of the "opt-out." New PJM Cos. Rehearing at 35; See also Cinergy rehearing at 3-4 and GridAmerica rehearing at 13-15. However, Detroit Edison opposes the SECA and asks why the Commission did not reject the SECA based on the record in Docket No. EL02-111. See Detroit Edison Rehearing at 16-19.

[80] See, e.g., Cinergy Rehearing at 3-4; GridAmerica Rehearing at 13-15; Detroit Edison Rehearing at 16-19.

[81] See Multiple TDUs Rehearing at 12.

[82] See Detroit Edison Rehearing at 20-26; Certain Classic PJM TOs Rehearing at 28.

[83] See Detroit Edison Rehearing at 8-9.

[84] See; e.g., Detroit Edison Rehearing at 5-6, New PJM Cos. Rehearing at 6; Illinois Power at 3-4; MI Agencies at 7-8; WEPCO Answer to New PJM Cos.' Motion for Clarification at 10-11.

[85] In support, Detroit Edison cites Missouri Pub. Serv. Comm'n. v. FERC, 337 F.3d 1066 (2003) (Missouri PSC).

[86] Detroit Edison also states that the Commission mischaracterized the testimony it co-sponsored as part of TRRG. Detroit Edison states that its testimony was not meant to show that the existing rates are excessive; rather the testimony included cost and revenue analysis to demonstrate that the reasonableness of a lost revenue recovery proposal cannot be evaluated without considering both costs and revenues.

f. Commission Determination

42. In the July 23 Order, we stated that we are not obligated to establish a lost revenue recovery mechanism noting that, in earlier orders, the Commission approved the elimination of rate pancaking without transitional mechanisms to recover lost revenues.[87] However, on reconsideration, we recognize that, in those cases, the transmission owners voluntarily agreed to eliminate rate pancaking without a lost revenue recovery mechanism. Here, however, the parties do not agree to eliminate rate pancaking without a lost revenue recovery mechanism. Their concerns include the recovery of lost revenues and resulting cost shifts[88] that would occur upon the elimination of RTORs without simultaneously replacing them with a lost revenue recovery mechanism.[89]

43. As discussed below, we find that these parties have raised valid concerns, grant rehearing and make findings with respect to an appropriate transitional lost revenue recovery mechanism to be established in this proceeding. As we stated in the July 23 Order, the record does not give the Commission a sufficient basis to establish the proposed SECA as a superseding rate. Even the Midwest ISO TOs, who filed testimony that included SECAs calculated for the region, stated that their calculated rates were not proposed at this time for Commission approval.[90] Instead of requiring that any filings seeking to recover lost revenues be made under FPA Section 205, we will direct Section 206 compliance filings that will contain a transitional surcharge to recover lost RTOR revenues, consistent with our findings herein, which can be implemented simultaneously with the elimination of the Midwest ISO and PJM RTORs on April 1, 2004.

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[87] See PJM Interconnection, L.L.C., 81 FERC ¶ 61,257 (1997); see also Midwest Independent Transmission System Operator, Inc., et al., Opinion No. 453, 97 FERC ¶ 61,033 (2001), order on reh'g, Opinion No. 453-A, 98 FERC ¶ 61,141 (2002).

[88] See, e.g., New PJM Cos. Rehearing at 32-22; Midwest ISO TOs Rehearing at 9-10; GridAmerica Rehearing at 9-12.

[89] For example, Certain Classic PJM TOs state that eliminating RTORs without a lost revenue recovery mechanism would shift costs from Midwest ISO's native load to PJM's native load and there may be other costs shifts such as from generators in Midwest ISO to load in PJM. Certain Classic PJM TOs Rehearing at 11.

[90] See Exhibit No. MISO TOs-1, p. 25: 13-9. Mr. Heintz states that the data is not confirmed and checked and would need to be done so in a compliance filing.

44. As the Presiding Judge pointed out, without a SECA-like mechanism, there would be a significant cost-shift between the native loads of the two RTOs.[91] Transitional lost revenue recovery mechanisms such as the proposed SECAs can serve as reasonable transitional mechanisms to address revenue losses and potential cost shifts arising from the elimination of rate pancaking.[92] By recovering lost revenues from each zone proportionate to the benefit that each zone receives from the elimination of rate pancaking, and recovering such costs through a non-bypassable surcharge for delivery within the zone, such transitional lost revenue recovery mechanisms better control cost-shifting than conventional license plate rates without transitional surcharges while simultaneously avoiding the injurious effects on efficient use of the grid associated with rate pancaking.[93] By fixing the superseding rate in this Section 206 proceeding, the Commission will mitigate cost shifting during the transition period to ensure just and reasonable rates upon the elimination of the RTORs.

45. We recognize the concern of some parties that generators may benefit to some extent from the elimination of the RTORs, and that those savings may not all be passed on to load serving entities (LSEs). However, we believe that the remedies provided by this order contain features that adequately mitigate any such impact. First, as discussed above, we require that any transmission customer that currently has a long-term firm transmission reservation effective before April 1, 2004, including those that are not load-serving entities, will continue to pay the RTOR, thus limiting the amount of lost revenues to be recovered from load. Second, customers serving load in the combined region will be able to reserve service from the point where power is injected into the combined region to the ultimate delivery point from which load is served, for a single non-pancaked

[91] As the Presiding Judge noted, native load customers are ultimately responsible for the costs of the utility's transmission system. Therefore, these mechanisms offset part of the cost of the transmission system that otherwise would be paid by the native load. These mechanisms prevent the transmission rates of native load from increasing as a result of the elimination of rate pancaking. For example, the Midwest ISO Tos are under a formula rate, which absent these mechanisms, would automatically the transmission rate to the rest of the customers (e.g., native load).

[92] We note that proposals for lost revenue recovery mechanisms to address the elimination of intra-RTO rate pancaking when GridAmerica joins Midwest ISO and when the New PJM Cos. join PJM in Docket Nos. ER03-580 and ER03-262, respectively, are currently the subject o hearing and settlement procedures. We believe that the transitional rate mechanisms associated with the elimination of intra-RTO rate pancaking within the combined region should be the same as the mechanism prescribed here for the elimination of inter-RTO rate pancaking.

[93] See April 25 Order.

charge, thus enabling load-serving entities to negotiate power supply contracts based on the market price where the resource is located, rather than where the load is located, without incurring additional access charges. Third, the elimination of the RTORs will result in more remote generation becoming economic for import, which will put downward pressure on market prices where load is located, resulting in lower costs for purchases from local generation as well as imports. Fourth, as part of the compliance filing process, we will allow LSEs under existing contracts for delivered power that continue into the transition period to demonstrate that the supplier is the shipper for such transactions and to propose that the supplier be required to pay the SECA for that portion of the LSE's load served by the contract.[94]

46. Detroit Edison characterizes the SECA as an incentive for RTO participation which requires a cost-benefit analysis under the provisions for incentive rates under the Policy Statement on Incentive Regulation.[95] Detroit Edison argues that the rates are incentive rates based on its claim that they are not cost-based because the Commission is not requiring an updated cost-of-service analysis. As an initial matter, we are not providing positive incentives, rather we are eliminating an unjust and unreasonable rate design and establishing a lost revenue recovery mechanism to mitigate cost-shifting and to hold transmission owners revenue neutral during a transition period to a new rate design.

47. We also disagree with Detroit Edison's characterization of the SECA as not cost-based. As explained below, we have previously accepted the existing cost-of-service and revenue levels of these companies as just and reasonable and our actions in this proceeding will maintain, not change, the level of these revenues. As we are only changing the design of existing rates, we are not departing from cost-based factors as Detroit Edison argues. Therefore, Detroit Edison's argument that the Commission is

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[94] Similarly, we recognize that a LSE with existing T&O service reservations that will continue into the transition period will continue to pay the RTORs. If such an LSE does not have its own sub-zonal SECA, the SECA may assess such LSE a disproportionate share of lost RTOR revenues. Therefore, we will allow such LSEs with existing transmission arrangements that continue into the transition period to demonstrate to the Commission the extent of disproportionate impact of paying both the RTOR and the SECA and propose an adjustment to its SECA obligation proportional to the RTOR charges it will continue to incur under the existing transmission arrangements.

[95] See Detroit Edison Rehearing at 8 (citing Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, 61 FERC ¶ 61,168 at 61,593-94 (1992)).

departing from cost-based factors is misplaced.[96] For these reasons, contrary to Detroit Edison's assertion, we are acting within our statutory responsibility to ensure that these rates remain just and reasonable.

48. In addition, the SECA prescribed by this order does not violate ratemaking principles as claimed by the parties.[97] Consistent with the principle of cost causation, the load of an importing utility should pay a fair share of the costs of the exporting utility's transmission facilities for its use of those facilities. Historically, such payments were made via transactional-based charges which have been determined by the Commission to no longer be just and reasonable for the combined region. Therefore, the Commission is developing the transitional rate mechanisms to ensure that the parties continue to pay the costs of facilities that they use and from which they benefit. The lost revenue recovery mechanisms are calculated based on the revenue recovered through the just and reasonable rate charged in a historical period for through and out service and will approximate the exporting utility's cost of providing such service to the importing utility's load. The new transition rate mechanism would allocate such costs in proportion to the benefits received while holding transmission owners revenue neutral. The transitional rate mechanism is designed to approximate the expected use of the exporting utility's transmission system during the two year transition period. Therefore, these lost revenue recovery mechanisms are consistent with the principle of cost causation during the transition period.

49. We also agree with the Presiding Judge that it is not necessary to require the filing of updated cost-of-service studies. We have previously accepted the existing rates of these companies as just and reasonable and our actions in this proceeding will maintain the revenues produced by those rates during the two-year transition period. In addition, some argue that the Commission indicated that an updated cost-of-service analysis was relevant to consideration of the transitional rate mechanism when it granted the interlocutory appeal of TRRG to admit testimony which suggested the transmission owners would vastly over earn their authorized rates of return. For example, TRRG's testimony suggested that transmission owners would receive an earned return on equity

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[96] Even if the lost revenue recovery mechanism was an incentive rate, the Commission may relax requirement of a cost-benefit analysis under certain conditions as it proposed in the Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid. See Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid, 102 FERC ¶ 61,032 (2003). Likewise, its reliance on Missouri PSC and other cases involving the Commission's departure from cost-based ratemaking is misplaced.

[97] We summarily affirm the Presiding Judge regarding his finding that the SECA does not result in retroactive ratemaking and does not violate the filed rate doctrine.

as high as 63 percent, prior to the elimination of wheeling revenues,[98] indicating that the existing rates may no longer be just and reasonable and thereby necessitating further inquiry. However, as the Presiding Judge correctly found, TRRG's analysis as well as the cost analyses provided by other parties were discredited, and at the conclusion of the hearing, these parties were unable to bear the burden of proof that the transmission owners' existing rates were unjust and unreasonable.[99] Therefore, based on the record in this proceeding, we have no reason to believe the transmission owners' existing rates or revenues are unjust and unreasonable or that transitional surcharges based on those rates and revenues are unjust and unreasonable.[100] Accordingly, Midwest ISO and PJM are not required to submit updated cost-of-service studies in their compliance filings.

50. Additionally, some parties claim that with the load-based design of the SECA, companies will overearn due to load growth. However, these parties fail to realize that the elimination of this unjust and unreasonable rate design can cause the expected load growth to be supplied by increased imports from the other side of the seam. Therefore, even though companies may have increased revenues from load growth, they can incur increased transmission costs to support the additional trading in the region. This effect of load growth on the SECA is typical for stated rates that are routinely accepted by the Commission in that the amount actually collected under the rates is determined by the difference between the actual load and the test period load used as the divisor of the rate.

51. As for the Certain Classic PJM TOs, we recognize that they may be in a position similar to sub-zones elsewhere in the footprint concerning their ability to determine where transactions sink within the control area. Consistent with our findings below concerning sub-zones, we direct the Midwest ISO to consult with the customers in PJM

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[98] See Exhibit No. DE/ITC-13 at 5:15-23.

[99] See GridAmerica Brief Opposing Exceptions at 21-22; New PJM Cos. Brief Opposing Exceptions at 38. We believe that we accurately reflected the essence of TRRG's testimony filed in the hearing containing the costs and revenues of other companies in the region.

[100] The Commission continues to monitor and review cost-based rates to ensure that they continue to be just and reasonable. To that end, the Commission recently proposed to revise its regulations by establishing new quarterly financial reporting requirements and making changes to its annual reporting requirements to provide the Commission with more timely, relevant, reliable and understandable financial information. This additional financial reporting will aid the Commission in, among other things, evaluating the adequacy of traditional cost-based rates, a task that would be made easier if utilities used formulaic rates. When we find reason to believe that the level of a rate on file may no longer be just and reasonable, we will take appropriate action.

regarding calculating the SECAs on a zonal or PJM-wide basis. If the PJM customers agree that they want their SECA calculated on a PJM-wide basis, then we order Midwest ISO and PJM to work together so that Midwest ISO may file a SECA on a PJM-wide basis. Otherwise, Midwest ISO and PJM should work together so that Midwest ISO can provide the data on a sub-zonal basis.

52. The opportunity to recover the transitional surcharges due to retail rate freezes should not present a problem. Because the surcharges are designed to reflect the historical costs of transmission service purchased to serve native load, they do not reflect new costs. However, consistent with our earlier orders concerning other RTO charges,[101] if any transmission owner is not provided adequate opportunity to recover these costs in retail rates, it may make a filing with the Commission demonstrating that it does not have adequate opportunity to currently recover those costs and seeking treatment of such costs as a regulatory asset under the Commission=s Uniform System of Accounts properly classified in Account No. 182.3, Other Regulatory Assets.[102]

53. Finally, parties have not shown why the change in rate design from a transactional-based charge to a load-based charge would affect the allocation of physical or financial transmission rights set forth in the RTOs' OATTs. Therefore, load in Midwest ISO that makes a contribution towards the cost of the transmission facilities of PJM through payment of a SECA and that makes a firm reservation on the transmission system of PJM is entitled to financial transmission rights per PJM's OATT. Similarly, load in PJM that takes the same actions with respect to Midwest ISO would be entitled to firm physical transmission rights under the Midwest ISO OATT.[103]

C. Specific Attributes of the SECA

54. In the July 23 Order, we gave guidance on specific attributes of the SECA to facilitate the filing of lost revenue recovery mechanisms under Section 205 of the FPA. Since that portion of the order merely provided guidance and did not adopt a SECA mechanism, we will not address the rehearing requests related to our prior guidance. In our discussion below we rely on the record in the hearing in this proceeding to make a determination on the specific attributes of the SECA that we are establishing herein.

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[101] See Midwest Independent Transmission System Operator, Inc., 102 FERC & 61,279 (2003) and Midwest Independent Transmission System Operator, Inc., order on remand, 102 FERC & 61,192, order on reh=g, 104 FERC & 61,012 (2003).

[102] See 18 C.F.R. § Part 101, Account No. 182.3 (2003).

[103] We do not address the allocation of financial transmission rights under the Midwest ISO OATT as Midwest ISO is still formulating its Day 2 energy market rules.

1. NERC Tag Data

a. Presiding Judge's Ruling

55. The Presiding Judge stated that the proposed SECAs should be modified to reflect the most current circumstances, and, specifically, the Presiding Judge recommended that the year 2002 should be the test period. The Presiding Judge reasoned that Midwest ISO was not in existence until February of 2002. Thus, if the lost revenues were calculated for the year 2001, the lost revenues for Midwest ISO would consist of the through and out charges under Midwest ISO transmission owners' individual company OATTs which have already been eliminated.[104]

56. The Presiding Judge stressed that the concern was with only eliminating the RTORs that currently exist and adopting a suitable replacement. The Presiding Judge added that evidence indicating that the RTORs were heavily discounted in 2002 was all the more reason to use that year as the test period to more realistically reflect in the SECA the rates and revenues that are actually going to be eliminated. The Judge stated that "the main purpose for using the year 2001 data as the test period, now that the figures for the year 2002 should be available, appears to be a desire to shelter a greater amount [of lost revenues] from the state rate caps. . ." and "if the lost revenues are calculated for the year 2001, as under the MISO TOs' proposal, the lost revenues in MISO would consist, for the most part, of the through and out charges between the transmission owners now in MISO that have already been eliminated." [105]

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[104] The Presiding Judge noted that apparently individual Midwest ISO transmission owners recovered $115 million in through and out revenues in the year 2000, and with the formation of the Midwest ISO and the elimination of internal pancaking in the year 2002, it was anticipated that revenues from the RTOR, if not discounted, would amount to $36 million. Initial Decision at n.25. The Presiding Judge added that how much more they were actually reduced by discounting was undisclosed by the record.

[105] See Initial Decision at P 91-92.

b. Briefs on Exceptions

57. Many parties excepted to the Presiding Judge's recommendation that 2002 be used as the test year for calculating a SECA.[106] For example, GridAmerica objected to the basis on which the Presiding Judge made his decision, claiming that the Presiding Judge erred because there is no connection between the issue of using 2001 as a test year and the retail rate caps. GridAmerica submitted that using a 2001 test year would not allow Midwest ISO members to collect revenues lost from eliminating pancaking solely within Midwest ISO.[107] In addition, it argued that since 2001 data were the only figures presented at hearing, the record does not support a finding that another year would be more representative of transaction behavior by participants. GridAmerica claimed that there are also other reasons that it is appropriate to use 2001 as the test year, including the fact that 2001 data is already part of the formal record and is "cleaner data" because 2002 data would reflect significant changes in market conditions due to the start-up of Midwest ISO and PJM West.[108] However, in the event that the Commission decides that a single test year is inappropriate, GridAmerica supported the averaging of calendar-year 2000, 2001, and 2002 data.[109]

58. Several parties supported averaging data for multiple years to establish the test period data.[110] They contended that averaging the test years will ameliorate anomalies in

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[106] See, e.g., GridAmerica Brief on Exceptions at 9; Midwest ISO TOs Brief on Exceptions at 11; Madison Brief on Exceptions at 9; Maryland and Pennsylvania Commissions Brief on Exceptions at 16-17; Ohio Commission Brief on Exceptions at 4; Wisconsin Brief on Exceptions at 22; WEPCO Brief on Exceptions at 31; and WPSC/UPPCo Brief on Exceptions at 9.

[107] See GridAmerica Brief on Exceptions at 17-18.

[108] The Midwest ISO TOs also urged the Commission to accept 2001 as the test year, at least for the Midwest ISO TOs, arguing that 2002 data is aberrational with respect to themselves as it was the year of the Midwest ISO start-up and transactions through and out of the Midwest ISO footprint were initially suppressed due to problems with discounting and posting Available Transmission Capacity. See also Madison Brief on Exceptions at 9.

[109] See GridAmerica Brief on Exceptions at 21.

[110] See, e.g., Ohio Commission Brief on Exceptions at 4; Wisconsin Commission Brief on Exceptions at 9; WEPCO Brief on Exceptions at 32; WPSC/UPPCo Brief on Exceptions at 25.

any single year. TRRG did not except to the Judge's rejection of 2001 as a test year; however, TRRG did not support use of 2002 either. TRRG recommended that, if the Commission insists on a method of lost revenue recovery, it use the most recent 12 months of data available and that the surcharge be trued-up annually to actual transmission usage.[111]

c. Briefs Opposing Exceptions

59. MPSC agreed with the Presiding Judge's finding that 2002 be used as the test year for the SECA charge. It stated that 2002 is more representative of future imports to some Michigan and Wisconsin customers due to the addition of considerable new generation in Michigan. Consumers Energy concurred in this argument.

60. Dairyland stated that use of 2002 as a test year is adequately supported by the record. Commission Staff argued that 2002, or an average of multiple years, should be used because 2001 data is likely to lead to an over collection of lost revenues. Illinois Power also supported the use of a 2002 test period.

d. July 23 Order

61. In the July 23 Order, the Commission stated that as a general matter, in the context of a Section 205 filing, any such filing should use NERC tag data and develop lost through and out revenues for the most recent twelve months, with adjustments for known and measurable differences, to most closely reflect future trading patterns.[112]

e. Request for Rehearing

62. Most parties filing requests for rehearing recommend using calendar year 2002 data instead of the most recent 12 months.[113] However, the Midwest ISO TOs repeat the arguments raised in their briefs in favor of calendar year 2001. Alternatively, the Midwest ISO TOs believe that the calendar year 2002 should be used because it will allow parties to synchronize with the reporting period of the FERC Form No. 1 and the data is already available. Additionally, Certain Classic PJM TOs believe that the Commission's willingness to entertain adjustments to the test period for known and

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[111] See TRRG Brief on Exceptions at 70.

[112] See July 23 Order at P 54.

[113] See New PJM Cos. Rehearing at 36.

measurable differences in trading is subject to potentially significant factual disputes which would be best resolved based on evidence presented at a hearing.[114]

63. Further, the Michigan Commission believes that NERC tag data can be manipulated to create significant inaccuracies; therefore, it states that the Commission should adopt a "fail safe" mechanism to protect Michigan consumers.[115] Multiple TDUs believe that actual invoices should be used to determine any lost revenues.[116]

f. Commission Decision

64. We agree with the Presiding Judge's recommendation to use the most recent data to calculate the transitional rate mechanisms, which, at the close of the hearing, was the 2002 test period.[117] In addition to the reasons stated in the Initial Decision, Commission trial staff noted that changes in generation throughout the region in 2001 and 2002 make 2001 less representative of expected future trade patterns.[118] However, since the Presiding Judge issued his Initial Decision, additional NERC tag data became available. We believed that the use of the most recent NERC tag data would be even more reflective of future trading patterns; therefore, in the July 23 Order the Commission recommended the use of the most recent twelve months of data.

65. However, since the issuance of the July 23 Order, the Commission has received feedback suggesting that while more recent data are available, significant work would be necessary to prepare that data, making it infeasible to utilize for filings by November 1, 2003, as contemplated in the July 23 Order. Several parties suggest using calendar year

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[114] See Certain Classic PJM TOs. Rehearing at 32-33.

[115] See Michigan Commission Rehearing at 7.

[116] See Multiple TDUs Rehearing at 12.

[117] During the hearing, TRRG proposed that the SECA be trued up based on actual usage of through and out service. We reject this proposal because a true-up, as TRRG proposes, would essentially convert the SECA back into a transactional charge for through and out service, thus recreating the impacts of rate pancaking which we are eliminating.

[118] Several large nuclear plants were out of service for extended periods of time in 2001. Additionally, the record indicates that Michigan and Certain Classic PJM TOs have increased generation capacity in locations that would avoid the RTOR subsequent to 2001. Trial Staff Brief Opposing Exceptions at 33-34.

2002 data for administrative convenience.[119] Even the Midwest ISO TOs, who would prefer 2001 calendar year data, alternatively recommend using calendar year 2002 data.

66. On October 14, 2003, the New PJM Cos. filed in Docket No. EL02-111-007, et al., a regional SECA proposal to replace the through and out rates for transactions sinking in the Midwest ISO/PJM footprint. New PJM Cos. recommend in the proposal to use 2002 NERC tag data for the first year of the transition period and the most recent twelve months of data for the second year of the transition period. New PJM Cos. state that the purpose for redetermining the SECA in this manner is an attempt to comply with the Commission's requirement to use the most recent data, while also using data that make filings by November 1, 2003 feasible. The Commission believes that New PJM Cos.' proposal addresses the concerns of the parties and our original concerns. We will, therefore, require that the SECA be based on a calendar year 2002 test year period in the first year of the transition period and a calendar year 2003 test year for the second year of the transition period.

67. We reject the suggestion of some parties to base SECA charges on actual invoices, instead of NERC tag data, to ensure that the SECA does not charge parties more than the actual RTOR charges paid in the test period. Using actual invoices as the basis for the SECA charges could lead to under recovery of lost revenues and produce unfair results as many of the transmission customers are marketers that can change their level of trading activity from year to year. Further, as we explained above, since load ultimately benefits from the through and out service, assessing the lost revenues to load is just and reasonable.

2. Transition Period

a. Presiding Judge's Ruling

68. The Presiding Judge stated that the SECA should remain in place until a long-term solution could be established. Otherwise, the Presiding Judge believes that cost shifts will occur between the native loads of the two RTOs.

69. The Presiding Judge also rejected Midwest ISO TOs' proposal that the SECA be phased-out over a three-year period, and, instead, found that it should remain in effect until another methodology is devised to insure that there is no cost shifting to PJM's native load customers. The Presiding Judge explained that if the RTORs were eliminated

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[119] See, e.g., New PJM Cos. Motion for Clarification at 5; GridAmerica Motion for Clarification at 11; Midwest ISO TOs rehearing request at 7-8 (supporting use of the most recent calendar year if the Commission fails to grant rehearing and allow the use of 2001 year data).

without being replaced by a SECA, costs would be shifted from the Midwest ISO's native load to PJM's native load because PJM does more exporting to the Midwest ISO than vice versa. The Presiding Judge added that phasing out the SECA after the first year would be objectionable because it would result in PJM's native load subsidizing use of the PJM transmission system to serve the Midwest ISO=s native load.[120]

b. Briefs on Exceptions

70. Multiple parties objected to the Presiding Judge's failure to adopt a finite transition period.[121] Edison Mission contended that a SECA should be established strictly as a transitional mechanism, consistent with previous Commission direction.[122] The Michigan Agencies contended that adopting a SECA without a definite end to the transition period could be more harmful than the existing rate pancaking. WPSC and UPPC noted that a three-year transition period is consistent with the transition period reached in the Illinois Power Settlement, which they noted, the Commission pointed to as useful guidance in the July 31 Order.[123]

71. Several parties argued that a SECA should be phased out over a three-year transition period as proposed by the Midwest ISO TOs.[124] They contended that a phase out is necessary in order to mitigate the potential for over recovery of lost revenues and to

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[120] See Initial Decision at P 93.

[121] See, e.g., Edison Mission Brief on Exceptions at 11, Trial Staff Brief on Exceptions at 10, Consumers Brief on Exceptions at 43-44, Dairyland Power Brief on Exceptions at 4-5, Madison Brief on Exceptions at 8, Maryland and Pennsylvania Commissions Brief on Exceptions at 6, Michigan Agencies Brief on Exceptions at 24, Wisconsin Commission Brief on Exceptions at 8, WPSC/UPPCo Brief on Exceptions at 22, Michigan Commission Brief on Exceptions at 17, TRRG Brief on Exceptions at 66.

[122] See Edison Mission Brief on Exceptions at 11(citing Illinois Power Co., 95 ¶ FERC at 63,004).

[123] See WPSC/ UPPCo Brief on Exceptions at 26.

[124] See, e.g., Edison Mission Brief on Exceptions at 12, Trial Staff Brief on Exceptions at 16, Consumers Brief on Exceptions at 43, Dairyland Power Brief on Exceptions at 4-5, Madison Brief on Exceptions at 8, Maryland and Pennsylvania Commissions Brief on Exceptions at 6, Michigan Agencies Brief on Exceptions at 24-25, Wisconsin Commission Brief on Exceptions at 8, WPSC and UPPC Brief on Exceptions at 26, Michigan Commission Brief on Exceptions at 17-18, TRRG Brief on Exceptions at 67.

ameliorate some of the problems resulting from anomalous test year data. Trial Staff also supported a phase out because it strikes a balance between those supporting a full SECA without phase out and those opposed to any lost revenue recovery.[125]

c. Briefs Opposing Exceptions

72. Several parties stated that the SECA charge is not a long-term remedy. Ormet Primary Aluminum Corp. believed that the appropriate long-term transmission rate for the common Midwest ISOPJM market is a single system rate.[126] WEPCO agreed that the Commission should focus on developing a permanent solution with the formation of the Midwest ISO/PJM common market.[127] WPSC also cautioned that the transition period should be as short as possible to minimize any opportunity for gaming.[128]

d. July 23 Order

73. The July 23 Order stated the transitional period for a SECA should be as short as possible, while allowing enough time for parties to develop a permanent rate design to efficiently price transmission service between the regions. The Commission found that a two-year transition period for a transitional cost recovery mechanism will provide sufficient time for the parties to establish a permanent rate design that efficiently prices transmission service between regions in the Midwest ISO and PJM footprint.

e. Request for Rehearing

74. Detroit Edison believes that the Commission was wrong to indicate that the concept of inter-regional payments may be applicable to the proposed Midwest ISO/PJM footprint. Detroit Edison argues that the Midwest ISO and PJM are so poorly configured that transactions crossing the seam between Midwest ISO and PJM should be considered intra-regional transactions that would not be subject to inter-regional payments over the long term. Michigan Agencies request the Commission to clarify that its silence on the phase-out provision does not constitute rejection of the proposal; otherwise, a rejection of the phase-out provision will create unjust results for several parties.[129]

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[125] See Trial Staff Brief on Exceptions at 17.

[126] See Ormet Brief Opposing Exceptions at 6.

[127] See WEPCO Brief Opposing Exceptions at 3.

[128] See WPSC Brief Opposing Exceptions at 13.

[129] See Michigan Agencies Rehearing at 12-14.

f. Commission Decision

75. We conclude that a two-year transition period is sufficient time for the parties to establish a permanent rate design that efficiently prices transactions for inter-RTO pricing in the PJM/Midwest ISO footprint.[130]

76. We agree with the Presiding Judge that no phase-out of the SECA is warranted. The Midwest ISO TOs state that 2001 test year data are not representative of the trading patterns that would occur in the RTOs and could lead to over-recovery and that phasing-out the SECA will mitigate any such potential for over-recovery. However, our decision to use data for the twelve-month period for calendar years 2002 and 2003 and a two-year transition period will mitigate the over-recovery suggested by the Midwest ISO TOs. We note that with a two year transition period, the result will be two years of recovery of the SECA which provides the same result as the Midwest ISO TOs' proposal with a phase-out over three years.[131]

3. Adjustments for "Hubbing" Transactions

a. Presiding Judge's Ruling

77. The Presiding Judge ruled that the SECA should replace only charges for through and out service for transactions that sink in either the expanded PJM or the Midwest ISO and source in or wheel through the other RTO. The Presiding Judge noted that, if power is transmitted through or out of one RTO and delivered to load in the other RTO, the exporting RTO's system is used to transmit that power for the benefit of the load to which

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[130] With respect to Detroit Edison's concerns about the long-term solution to pricing transmission service between regions in the July 23 Order, we did not intend to prejudge the appropriate solution to pricing transmission service between RTOs in this region as that issue is not yet ripe. However, we are encouraged that Detroit Edison is thinking about issues associated with a fair and efficient long-term solution to pricing transmission between the RTOs. We encourage the parties to begin negotiations on the long-term solution to pricing transmission service and encourage Detroit Edison to participate in those negotiations.

[131] In the first year of the transition period under the Midwest ISO's phase-out proposal, the SECA would be 100% of the transmission owner's SECA, in the second year, the SECA would be reduced to 66% of the first year amount and in the third year the SECA would be reduced to 33% of the first year amount. Overall, the Midwest ISO TOs proposal is equivalent to two years of full lost revenue recovery, spread out over three years.

the power is delivered and which would have to pay an RTOR if it was not eliminated. However, the Presiding Judge noted that, in "hubbing transactions", in which power is transmitted through or out of either PJM or Midwest ISO to the other RTO, but ultimate delivery is outside of the importing RTO, the load receiving the ultimate delivery is currently responsible for all charges. The Presiding Judge found that reflecting such transactions in the SECA charged to load in the RTO through which the power is transmitted, but does not sink, would improperly charge that load with the costs not incurred for its benefit and for transactions for which it would not previously have been charged an RTOR.[132]

b. Brief on Exceptions

78. Illinois Power agreed with the Initial Decision that a SECA should reflect adjustments for hubbing transactions; however, it asserted that the Commission should clarify that transmission owners should make these adjustments in consultation with LSEs, prior to submitting SECA calculations in a compliance filing.[133]

c. July 23 Order

79. The July 23 Order did not address hubbing transactions.

d. Commission Decision

80. This issue arises because NERC tag data shows certain transactions sinking in a particular control area, whereas the underlying transactions actually served load in another control area, either in the same RTO or outside of the RTO. We agree with the Presiding Judge and order the parties to make adjustments to the NERC tag data submitted in the compliance filings ordered herein to remove such "hubbing" transactions. Furthermore, to reduce the number of contested transactions, we encourage transmission owners and providers to consult with the interested parties prior to filing their compliance filings. And, as discussed later in this order, we will provide the parties 45 days in which to make their compliance filings.[134]

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[132] See Initial Decision at P 96.

[133] See Illinois Power Brief on Exceptions at 23.

[134] We normally require compliance filings to be made within 30 days of the Commission's order.

4. **Sub-Zones**

a. **Presiding Judge's Ruling**

81. The Presiding Judge stated that the Commission must decide as a matter of policy whether the SECAs should be developed for the sink RTO as a whole or whether separate SECAs should be developed for individual license plate pricing zones or sub-zones. The Presiding Judge noted that, under the Midwest ISO's TOs' SECA proposal, each cooperative, municipal, or retail LSE could elect to have its own SECA calculated on the basis of its own transactions during the test period. This sub-zonal option does not affect the total lost revenue responsibility for load in an RTO or zone. However, the Presiding Judge noted that choosing the sub-zone SECA affects the payments made by the remainder of the zone, which will pay the balance of the zonal revenue responsibility.[135]

b. **Briefs on Exceptions**

82. Several parties argued that the Presiding Judge erred in failing to specifically adopt a sub-zonal SECA.[136] They claimed that such an option would minimize cost shifting and more closely assign costs of eliminating the RTORs to those who benefit.

c. **Briefs Opposing Exceptions**

83. The Maryland and Pennsylvania Commissions objected to a sub-zonal SECA stating that SECA revenue responsibility cannot be rationally assigned to PJM LSEs. JCA also objected to sub-zone SECA charges, in part, because Classic PJM Cos. are treated as one control area and the SECA may not accurately assign the costs on a zonal or sub-zonal basis.

d. **July 23 Order**

84. In the July 23 Order, the Commission stated that it would allow charges on a sub-zonal basis, since sub-zonal charges best align the benefits of eliminating rate pancaking with the associated lost revenues. The Commission reasoned that transactions cannot be traced to load in various zones of the Classic PJM Cos.' region because of operation of the PJM spot market and stated that Classic PJM Cos. should address alternative

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[135] See Initial Decision at P 97.

[136] See, e.g., Dairyland Power Brief on Exceptions at 5-6, Midwest ISO TOs Brief on Exceptions at 26, Michigan Agencies Brief on Exceptions at 27. Other parties indicated their support of a sub-zonal option, but submitted such arguments in their Briefs Opposing Exceptions (Illinois Power at 17; New PJM Cos. at 32).

methodologies for evaluating the relative benefits from import transactions between the various zones of the Classic PJM COs.' region.

e. Commission Decision

85. We will allow the SECA to be charged on a sub-zone basis. The SECA is designed to collect revenue from each zone, or sub-zone, in proportion to the benefits that the load within the zone, or sub-zone, will realize when it no longer has to pay pancaked rates for transmission purchased from transmission owners in the other RTO to serve its load. We find that, by permitting the SECA to be charged on a sub-zone basis, the benefits of eliminating rate pancaking are more closely aligned with the associated lost revenues so that load will not be significantly burdened by the transition to a common market.

86. However, we note that some parties believe that the determination of SECAs by sub-zones is difficult to administer. We acknowledge that customers within a zone will have to balance the benefits of creating sub-zonal SECAs against the difficulty in administering the SECA on a sub-zone basis. Therefore, we will accept calculation of the SECA on a sub-zonal basis unless all the sub-zones within a zone agree otherwise. We note that whether the SECA is calculated on a zonal or sub-zonal basis, the overall cost responsibility for the zone should remain the same.

87. We direct the Midwest ISO and PJM to consult with the customers in the other RTO as to whether they want their SECA calculated on a zonal or sub-zonal basis. If the parties in the zone agree that they want their SECAs calculated on a zonal basis, then we order Midwest ISO and PJM to submit their data on a zonal basis. Otherwise, Midwest ISO and PJM should provide the data on a sub-zonal basis.

5. Opt-Out for Michigan and Wisconsin

a. Presiding Judge's Ruling

88. The Presiding Judge ruled that Michigan and Wisconsin customers should be able to opt out of the SECA and continue paying the RTORs. The Presiding Judge noted that the record indicates that Michigan and Wisconsin will have more on-system generation and import less in the future than in the historical test periods considered in this proceeding, noting in particular evidence that there would be an addition of considerable native zone generation in Michigan and Wisconsin in calendar-year 2003. The Presiding Judge stated that if Michigan and Wisconsin customers are expected to take and pay for considerably less through and out service in the future because their need for imported power would be less, a SECA based on past payments would be unfair and could not legitimately be considered a replacement for future lost revenues. The Presiding Judge added that it was no defense to the proposed opt-out that other customers are not given

the same option since no other customer groups appeared in this Section 206 proceeding to demonstrate a similar inequity. The Presiding Judge concluded that having forgone the use of this forum which was devised for that purpose, other customer groups may nonetheless still file a Section 206 complaint seeking to opt out of any SECA that may be adopted by the Commission for similar reasons.[137]

b. Briefs on Exceptions

89. Several parties objected to the Presiding Judge's finding that Michigan and Wisconsin customers should be allowed to opt out of a SECA charge and instead pay pancaked rates.[138] They asserted that permitting this opt out will mitigate the overall efficiencies resulting from eliminating pancaking in the rest of the region and/or that this opt out is unduly discriminatory and preferential.[139] GridAmerica stated that "a patchwork of zones potentially subject to RTORs interspersed within a region that has eliminated the RTORs will erode the benefits of the inception of the Midwest ISO/PJM real-time and day-ahead common markets currently under development."[140] Certain Classic PJM TOs asserted that allowing a Michigan and Wisconsin opt out would not only be unlawfully discriminatory, but would also violate the previously stated policy that no RTO be treated preferentially.[141] Illinois Power argued that an opt-out should not be allowed because there are other mechanisms, such as the sub zone options, that could address the concerns of Michigan and Wisconsin, without perpetuating the existence of pancaked rates.[142]

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[137] See Initial Decision at P 94.

[138] See, e.g., GridAmerica Brief on Exceptions at 21, Classic PJM Companies Brief on Exceptions at 19, Illinois Power Brief on Exceptions at 17, Maryland and Pennsylvania Commissions Brief on Exceptions at 19.

[139] For example, several parties argued that the Classic PJM region should also be allowed to opt out of paying a SECA, and instead pay the applicable RTORs, because Certain Classic PJM TOs will be disadvantaged as a result of the SECA and they did not cause the seams problems. See JCA Brief on Exceptions at 26-27, Certain Classic PJM TOs Brief on Exceptions at 19 and Maryland and Pennsylvania Commission Brief on Exceptions at 19.

[140] See GridAmerica Brief on Exceptions at 22.

[141] See Classic PJM Companies Brief on Exceptions at 19.

[142] See Illinois Power Brief on Exceptions at 21.

c. **Briefs Opposing Exceptions**

90. Midwest ISO TOs stated that the opt-out option is reasonable because it addresses the unique circumstances of Michigan and Wisconsin, including an unusually high level of imports during the 2001 test year due to generation plant outages, and significant increases in generation within Michigan and Wisconsin since then that will result in a decreased reliance on imports to serve load in Michigan and Wisconsin in the future. They argued that the SECA disproportionately impacts Michigan and Wisconsin customers, noting that these customers would end up paying approximately 81 percent of the SECA charges.[143] The Michigan Commission supported the right of Michigan and Wisconsin to have the option of continuing to pay the RTORs instead of paying the SECA charge. It argued that due to the considerable new generation locating in Michigan, it is unfair for Michigan and Wisconsin customers to pay SECA charges based on the level of past purchases.

91. Michigan Agencies also supported the opt-out, stating that, if not for the New PJM Cos.' choice to join PJM, the Michigan and Wisconsin utilities would not be separated from the rest of the Midwest ISO footprint and would not incur charges that would not have existed had the former Alliance Companies joined Midwest ISO instead of PJM.

92. Consumers supported Michigan and Wisconsin's being allowed to opt-out, but only for the transition period during which the SECA would be in effect. Commission staff supported the opt-out provision as a means of mitigating the heavy financial burden on entities in Michigan and Wisconsin.

93. New PJM Cos. asserted that the opt-out provision is not supported by substantial and persuasive record evidence.[144] However, Michigan Agencies requested the Commission to clarify that its silence on the opt-out provision does not constitute rejection of the proposal. According to Michigan Agencies, a rejection of the opt-out provision will create unjust results for several parties.[145]

d. **Commission Decision**

94. While we understand the concerns about the impacts on Michigan and Wisconsin entities as a result of the lost revenue recovery mechanism, the Commission cannot allow

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[143] See TRRG Brief on Exceptions at 59.

[144] See New PJM Cos Rehearing at 35.

[145] See Michigan Agencies Brief Opposing Exceptions at 12-14; Michigan Commission Brief Opposing Exceptions at 5-6.

Michigan and Wisconsin entities to "opt-out" of the SECA and continue to pay pancaked rates. The Commission has already found that rate pancaking distorts economic choices and precludes the benefits of more efficient and competitive markets.

95. The Midwest ISO TOs, which proposed the opt-out provision on behalf of Michigan and Wisconsin entities, presented three reasons for the opt-out provision.[146] First, Midwest ISO TOs stated that creation of the Midwest ISO creates other economic paths that may be available to customers who in 2001 used the former Alliance Companies' systems. Second, they maintain that a significant portion of the MWs shown by the NERC tag data to be sinking in Michigan was exported to Canada under exclusive international border buy-resale restrictions that are no longer in place. Third, they submit that the test year data are not representative for other reasons, such as an unusual level of generation plant outages in 2001.[147]

96. We find that the use of data for the 2002 and 2003 calendar years will be more representative of future economic paths than 2001 test period data because that data will not reflect the 2001 unit outages which concerned the Midwest ISO TOs and will include new generation that came on line in Michigan since 2001. In addition, since we are agreeing with the Presiding Judge regarding adjustments to the NERC tag data for "hubbing" transactions in the development of the SECA, Michigan and Wisconsin customers will have the opportunity to show in the implementation stage that transactions tagged as sinking in their zones actually sink in another zone or RTO as a result of buy-sell transactions. Moreover, the two year transition period we have ordered will mitigate the effects of the SECA on Michigan and Wisconsin. Therefore, we find that with the modifications we have ordered, the SECA is just and reasonable as a transitional rate mechanism to be assessed to Michigan and Wisconsin entities to mitigate cost shifts that would otherwise occur due to the elimination of the RTORs.

D. Compliance Filings

97. As explained earlier, the Commission is granting rehearing and taking action to establish a transitional lost revenue recovery mechanism in this proceeding. Midwest ISO and PJM are directed to file compliance filings to change the rate design by eliminating the RTORs for transactions sinking in the combined region and implementing lost revenue recovery mechanisms consistent with the findings in this order, within 45 days of the date of this order. This should provide Midwest ISO and PJM with sufficient time to consult with the parties. Midwest ISO and PJM should also provide all

[146] Detroit Edison, as a member of TRRG, also states that its transmission bill will increase significantly as a result of the SECA.

[147] See Ex. MISO TOs-1 at 20.

supporting documents containing all calculations and data, including NERC tag data. We expect the parties in the region to work cooperatively in the preparation of these filings, and encourage them to attempt to resolve issues before the filings are made.

The Commission orders:

(A) The requests for rehearing of the July 23 Order that pertain to Docket No. EL02-111 are hereby granted in part, and denied in part, as discussed in the body of this order.

(B) Midwest ISO and PJM are hereby directed to submit compliance filings, within 45 days of the date of this order, as discussed in the body of this order.

(C) Midwest ISO is hereby directed to consult with the customers in PJM regarding calculating their transactions, and Midwest ISO and PJM are hereby directed to work together regarding the submission of Midwest ISO's data, as discussed in the body of this order.

(D) Midwest ISO and PJM's compliance filings in Docket Nos. EL02-111-005, EL02-111-006 and EL02-111-008 are hereby dismissed, as discussed in the body of this order.

(E) New PJM Companies' regional SECA proposal and complaints filed in Docket Nos. EL02-111-007 and EL03-212-002 and EL03-4-000, et al. are hereby dismissed, as discussed in the body of this order.

(F) Midwest ISO and PJM are hereby directed to submit to the Commission, within six months from the date of this order, and for each six-month period thereafter, a report detailing the progress made to develop a long-term solution to inter-RTO pricing for the Midwest ISO/PJM region to take effect at the end of the two-year transition period.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 4 of the Direct Testimony and Exhibits on Rehearing of J. Craig Baker ("Baker Testimony"), lines 11-15.

Provide a summary of how the Seams Elimination Charge Adjustment ("SECA") will be paid by loads in the affected area and identify affected areas.

RESPONSE

The SECA charges will be billed to parties serving loads in the service areas of the transmission providers required by the Order to make compliance filings. How the loads will pay the charges is not specified in the order.

WITNESS: J Craig Baker

105 FERC ¶ 61, 216

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, and Nora Mead Brownell.

Docket Nos. EL03-212-000
EL03-212-001

Ameren Services Company
on behalf of:
Union Electric Company
Central Illinois Public Service Company

American Electric Power Service Corporation
On behalf of:
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Kingsport Power Company
Ohio Power Company
Wheeling Power Company

Dayton Power and Light Company

Exelon Corporation
On behalf of:
Commonwealth Edison Company
Commonwealth Edison Company
of Indiana, Inc.

FirstEnergy Corporation
On behalf of:
American Transmission Systems, Inc.

Illinois Power Company

Northern Indiana Public Service Company

ORDER FINDING EXISTING RATE DESIGN FOR THROUGH AND OUT SERVICE UNJUST AND UNREASONABLE, DIRECTING COMPLIANCE FILINGS TO IMPLEMENT NEW RATE DESIGN, AND DENYING REHEARING

(Issued November 17, 2003)

1. In this order, we find that the rate design for through and out (T&O) service under the individual Open Access Transmission Tariffs (OATTs) of certain former Alliance Companies (Companies or former Alliance Companies)[1] is not just and reasonable when applied to transactions sinking in the proposed Midwest Independent Transmission System Operator (Midwest ISO)/PJM Interconnection, LLC (PJM) region (i.e., the combined footprints of the Companies, Midwest ISO and PJM, hereinafter "combined region") and we require the Companies to file compliance filings to implement a new rate design for such service, effective April 1, 2004. In addition, we deny requests for rehearing of the July 23 Order[2] that relate to Docket No. EL03-212-000.[3] This order benefits customers because it ensures that the rate design under the individual-company

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[1] American Electric Power Service Corp. on behalf of Appalachian Power Co., Columbus Southern Power Co., Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co., and Wheeling Power Co. (collectively, AEP), Ameren Services Co. on behalf of Union Electric Co. and Central Illinois Public Service Co. (collectively, Ameren), Commonwealth Edison Co. on behalf of itself and Commonwealth Edison Co. of Indiana (collectively, ComEd), FirstEnergy Corp. on behalf of American Transmission Systems, Inc. (ATSI) (collectively, FirstEnergy), Illinois Power Co. (Illinois Power), Northern Indiana Public Service Co. (NIPSCO) and Dayton Power and Light Co. (DP&L).

FirstEnergy and NIPSCO are now members of the Midwest ISO as participants of GridAmerica, which commenced its operations on October 1, 2003. See Midwest ISO Press Release, GridAmerica Begins Operations Under Midwest ISO (October 1, 2003), http://www.miso.com. Accordingly, we will not discuss ATSI and NIPSCO as this order no longer applies to them, and we will dismiss them from this proceeding.

[2] Midwest Independent Transmission System Operator, et al., 104 FERC ¶ 61,105 (2003) (July 23 Order).

[3] Rehearing requests of the July 23 Order concerning Docket No. EL02-111-000 are being addressed in an order in Docket No. EL02-111-004, et al., being issued concurrently with this order.

OATTs of non-regional transmission organization (RTO) members does not obstruct the realization of efficient and competitive regional electricity markets by RTO members.

I. Background

2. In the Initial Decision in Docket No. EL02-111-000,[4] the Presiding Judge determined that there was a lack of precedential authority that would permit him to eliminate the RTORs between the expanded Midwest ISO and expanded PJM under the circumstances of that proceeding. The Presiding Judge added that if, in a change of policy, the Commission was to order it, he would recommend that the Commission adopt, without requiring the filing of new rate cases, a mechanism such as one of the Seams Elimination Charge/Cost Adjustment/Assignment (SECA) proposals by the parties to prevent cost shifting between customers of the two RTOs.

3. In the July 23 Order, the Commission disagreed with the Presiding Judge's finding that there was a lack of precedential authority allowing him to eliminate the Regional Through and Out Rates (RTORs) between the expanded Midwest ISO and expanded PJM under the circumstances of that case. The Commission concluded that the Midwest ISO and PJM RTORs, when applied to transactions sinking within the Midwest ISO/PJM footprint, are unjust and unreasonable. The Commission directed PJM and Midwest ISO to make compliance filings within 30 days eliminating those RTORs, effective November 1, 2003. The Commission also stated that, even with the elimination of the Midwest ISO and PJM RTORs, in the near term the region will still be riddled with seams, with the T&O rates under the individual tariffs of the Companies acting as toll gates that impede the realization of more efficient and competitive electricity markets in the region and that preserve a competitive advantage for the non-RTO members' generation. Accordingly, the Commission established an investigation under Section 206 of the Federal Power Act (FPA)[5] in Docket No. EL03-212-000 to determine whether the Companies' T&O rates should be eliminated.

4. On October 14, 2003, the Commission issued an order in Docket Nos. EL02-111-000 and EL03-212-000,[6] extending the effective date for the elimination of the RTORs to

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[4] Midwest Independent Transmission System Operator, Inc., et al., 102 FERC ¶ 63,049 (2003) (Initial Decision).

[5] 16 U.S.C. § 824e (2000).

[6] Midwest Independent Transmission System Operator, et al., 105 FERC ¶ 61,060 (2003).

a date that was to be set in the order on rehearing of the July 23 Order, which is being issued concurrently with this order.[7]

II. Notice and Filings

A. Docket No. EL03-212-000

5. Notice of the initiation of proceedings and refund effective date in Docket No. EL03-212-000 was published in the Federal Register, 68 Fed. Reg. 46,175 (2003). The July 23 Order, which was published in the Federal Register, 65 Fed. Reg. 45,799 (2003), directed all notices of intervention to be filed with the Commission on or by August 8, 2003. The entities that filed timely and late motions to intervene or notices of intervention are listed in Appendix A of this order.

6. On August 15, 2003, AEP, Ameren, ComEd, DP&L, FirstEnergy,[8] Illinois Power and NIPSCO filed responses to the July 23 Order. On September 4, 2003, Wisconsin Public Service Corp. and Upper Peninsula Power Co. (WPSC/UPPCO) filed comments responding to the Companies' submittals, to which ComEd and DP&L jointly filed an answer. Ormet Primary Aluminum Corp. (Ormet) and Consumers Energy Company (Consumers Energy) also filed comments responding to AEP's submittal.

7. In addition, on August 15, 2003, Certain Classic PJM Cos. Transmission Owners[9] (Certain Classic PJM Cos. TOs) filed preliminary comments and Wisconsin Electric Power Co. and Alliant Energy Services Corp. (collectively, WEPCO/Alliant) and WPSC/UPPCO filed initial comments. AMP-Ohio; Cinergy Services, Inc. on behalf of Cincinnati Gas & Electric Co., PSI Energy, Inc. and the Union Light, Heat & Power Co. (collectively, Cinergy Services); Midwest ISO Transmission Owners (Midwest ISO

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[7] As stated in our concurrent order in Docket No. EL02-111-004, et al., the new effective date is April 1, 2004.

[8] On September 12, 2003, FirstEnergy filed a supplemental response to the July 23 Order.

[9] West Penn Power Co., Monongahela Power Co., Potomac Edison Co. all d/b/a Allegheny Power; Baltimore Gas and Electric Co., Pepco Holdings, Inc. and its affiliates Potomac Electric Power Co., Atlantic City Electric Co., and Delmarva Power & Light Co.; PPL Electric Utilities Corp.; Public Service Electric and Gas Co.; Rockland Electric Co.; and UGI Utilities, Inc.

TOs); Multiple TDUs;[10] Detroit Edison; Madison Gas and Electric Co. (MDG&E); and, jointly, Michigan Agencies[11] and the City of Hamilton filed comments. ComEd and DP&L filed a joint answer to the comments submitted in the proceeding.

B. Docket No. EL03-212-001

8. On August 4, 2003, New PJM Companies[12] (New PJM Cos.) filed a request for expedited clarification or, alternatively, rehearing of the July 23 Order. Illinois Power filed a motion in support of New PJM Cos.' request. Certain PJM Cos., Consumers Energy and Wisconsin Electric filed answers opposing New PJM Cos.' request, and Michigan Agencies filed a response in opposition to New PJM Cos.' and Illinois Power's filings. In addition, Coalition of Municipal and Cooperative Users of New PJM Cos. Transmission, Indiana Municipal Power Agency, Southeast Michigan System and Wisconsin Public Power, Inc. (collectively, Muni-Coop Coalition) jointly filed a response in opposition to New PJM Cos.' filing. Subsequently, New PJM Cos. filed an answer to the answers.

9. On August 11, 2003, GridAmerica Companies[13] (GridAmerica) filed a request for clarification and request for expedited consideration, and Michigan Agencies filed a partial answer opposing Grid America's filing and subsequently filed a response to GridAmerica's filing. New PJM Cos. and Detroit Edison also filed answers. On August 14, 2003, New PJM Cos filed a supplement to its answer to the answers, to which Multiple TDUs filed an answer. On August 22, 2003, Midwest ISO TOs filed motions for clarification. Cinergy Services filed an answer to Midwest ISO TOs' motion for clarification.

10. On August 15, 2003, Illinois Power filed a request for rehearing of the July 23 Order as it pertains to the ongoing FPA Section 206 investigation that included a

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[10] Indiana Municipal Power Agency; Michigan Cities of Croswell, Dowagia, Sebewaing and Sturgis; Nordic Energy; and Thumb Electric Cooperative; ElectriCities of North Carolina, Inc.; Blue Ridge Power Agency; Central Virginia Electric Coop.; Craig-Botetourt Electric Coop.; Old Dominion Electric Coop.; and Virginia Municipal Electric Assoc. No. I.

[11] Michigan Public Power Agency and Michigan South Central Power Agency.

[12] AEP, ComEd, and DP&L.

[13] Ameren Services and FirstEnergy.

response and suggestions for future actions. On August 22, 2003, AEP, ComEd, DP&L, Grid America, and the Pennsylvania Commission filed requests for rehearing.

IV. Discussion

A. Procedural Matters

11. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(c) (2003), the timely, unopposed motions to intervene and notices of intervention serve to make the entities that filed them parties to this proceeding.

12. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2003), we will grant the entities' untimely motions to intervene, in light of their interest in this proceeding, the early stage of the proceeding, and the absence of any undue prejudice or delay.

13. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2003), prohibits an answer to an answer unless otherwise ordered by the decisional authority. We will accept Multiple TDUs', New PJM Cos.' and Commonwealth Edison's answers, as they have aided us in our decision making process in this proceeding.

B. Justness and Reasonableness of Companies' T&O Rates

14. In the July 23 Order, the Commission found that even with the elimination of the Midwest ISO and PJM RTORs, in the near term, the region will still be riddled with seams, with the T&O rates under the Companies' tariffs acting as toll gates that impede the realization of more efficient and competitive electricity markets in the region and that preserve a competitive advantage for the non-RTO participants' merchant functions. The Commission provided the Companies with an opportunity to explain to the Commission why the T&O rates under the individual-company OATTs are or are not unjust, unreasonable or unduly discriminatory or preferential. As explained below, consistent with our responsibility under the FPA to ensure that rates, charges and practices of public utilities are just and reasonable,[14] we find that the T&O rates are unjust, unreasonable and unduly discriminatory or preferential.

[14] 16 U.S.C. § 824d (2000); 16 U.S.C. § 824e (2000).

1. Ameren

15. Ameren expects the Section 206 investigation will become moot as it anticipates joining an RTO by November 1, 2003.[15] Ameren contends that its T&O rates are just and reasonable and should not be eliminated without providing for continued recovery of the revenues lost by their elimination. Ameren states that to eliminate its T&O rates without a lost revenue recovery mechanism would be unjust and unreasonable and a retail rate freeze leaves it without means of recouping lost T&O service revenues until at least mid-2006.[16] It requests that the Commission find that the continued application of its individual T&O rates is just and reasonable until it joins an RTO. However, Ameren is willing to waive its T&O rates subject to: (1) the simultaneous elimination of the T&O rates of all transmission providers in the proposed Midwest ISO/PJM footprint; and (2) the Commission's adoption of a replacement lost revenue recovery mechanism.

2. ComEd

16. ComEd requests that the Commission conditionally dismiss it from this proceeding, subject to notice that it will be allowed to join PJM effective November 1, 2003.[17] ComEd expresses concern that it could be held responsible for refunds due to the October 4 refund effective date.

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[15] Ameren notes that proceedings before the Missouri Public Service Commission regarding Ameren's participation in GridAmerica have been suspended to allow parties to engage in settlement discussions. See Ameren Response at 6.

[16] Ameren states that the approximately $45 million in revenues that it collects from T&O rates applicable to transactions sinking outside its control area are embedded in cost-of-service studies that were the basis for its current bundled retail rates in Missouri. Ameren asserts that the approved retail rates resulted from a "black box settlement," and hence, there is no settlement cost-of-service line item labeled RTOR revenue. Ameren assumed that it would receive this revenue in the future to fund part of its transmission cost-of-service and that no additional revenues from Missouri ratepayers would be needed. See Ameren Response at 9 and Attachment A.

[17] We note, however, that PJM recently announced its extension of the date on which it will integrate ComEd into PJM as it is currently reviewing the events of the August 14 blackout and related reliability concerns. PJM will announce a new schedule for integrating ComEd and other transmission owners as its reliability review proceeds. See PJM News Release, Electricity Outage Lessons Learned to be Applied to Ongoing Integration Efforts (Aug. 20, 2003), http:// www.pjm.com.

17. In addition, ComEd contends that the July 23 Order does not present substantial evidence showing that its existing T&O rates are unjust and unreasonable or give adequate consideration to potential cost shifts to retail rate payers and utility shareholders if the T&O rates are eliminated.[18]

3. DP&L

18. In addition to the arguments against eliminating its T&O rates discussed later in this order,[19] DP&L claims that, pending its anticipated membership in PJM[20] and a simultaneous replacement of its existing transmission rate design, there is no basis to find its T&O rates unjust and unreasonable. In particular, DP&L states that the Commission's reference to "tollgates" does not apply to DP&L because, given its location in the region, transmission users have multiple options that would allow them to bypass the DP&L transmission system if its T&O rate was significantly out of line with available alternatives. It concludes that "it is highly unlikely that DP&L would or could act as a 'tollgate,' contrary to the Commission's assumption."[21]

19. DP&L also states that its currently effective rate design and rates, including its point-to-point rate applicable to T&O service, were established by settlement, effective

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[18] ComEd states that its currently effective rate design and rates were established by settlement in Docket No. ER99-4470-000, et al., effective February 5, 2000, and that its point-to-point rate is currently $0.950 per KW-month. It also notes that its bundled retail rates are frozen through January 1, 2005. See ComEd Response at 5.

[19] DP&L also expresses concern that the October 4, 2003 refund effective date would leave it without recourse to recover lost revenues if its T&O rate is eliminated on that date. See DP&L Response at 7. DP&L adds that the Commission's elimination of DP&L's existing rates would be discriminatory and unfairly singles out DP&L, as compared to other utilities that are not subject to this investigation. It states that the policy implications of such elimination include discouraging RTO development and transmission investment. Id. at 12.

[20] DP&L anticipates that its transmission system will be integrated into the PJM market and transmission service over its transmission system coming under the PJM OATT in Spring or Fall 2004.

[21] See DP&L Response at 10. In addition, AEP contests the characterization of its T&O rates as a toll gate and asserts that wholesale users of the transmission system should pay a fair share of the costs of its extensive transmission system. See AEP Response at 33.

December 19, 1997.[22] It asserts that currently a retail rate freeze is in place during the development period for retail competition, so if a change is made to the unbundled transmission component of retail rates to reflect the elimination of T&O service revenues, there would be an offsetting change to the distribution charge, effectively rendering it unable to pass this through to retail customers during the market development period.

4. Illinois Power

20. Illinois Power proposes to report back to the Commission by October 1, 2003 regarding its RTO plans. Illinois Power asserts that its rates are just, reasonable, and not unduly discriminatory or preferential and are entitled to a presumption of lawfulness because neither the Commission nor any other party has proven otherwise, in accordance with Section 206 of the FPA. It requests that the Commission provide guidance on appropriate transitional rate structures and that the Commission defer further action in Docket No. EL03-212-000 with respect to Illinois Power until October 1, 2003, by which time Illinois Power expects to be able to make a firm commitment on its RTO plans.[23]

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[22]DP&L cites Dayton Power and Light Co., 88 FERC ¶ 61,242 (1999).

[23] Exelon Corp. has since entered into an agreement with Dynegy Inc. to acquire substantially all of the operating assets of Illinois Power. The transaction is expected to close in the fourth quarter of 2004, pending regulatory approval and the passage of legislation in Illinois. In its announcement of the acquisition, Exelon stated that legislation, to be introduced in the Illinois General Assembly during its November session, is necessary to facilitate the acquisition and would give the Illinois Commerce Commission the authority to set rates for four year after the end of a state-mandated transition period on December 31, 2006. See Exelon News Release, Exelon Corporation Announces Acquisition of Illinois Power's Assets from Dynegy, Inc. (Nov. 3, 2003), *available at* http: //www.exeloncorp.com/corporate/newsroom. We note that at the September 29 and 30, 2003 hearing conducted by the Commission into the RTO status of certain of the former Alliance Companies, Illinois Power stated that will continue to evaluate its options for RTO participation in the event that no transaction with Exelon occurs. See Commission Inquiry into Midwest ISO/PJM RTO issues initiated in Docket No. ER03-262-001 et al.; Tr. at 184: 16-20. In addition, Exelon indicated that if the negotiations for the purchase of Illinois Power were successful, it planned to bring Illinois Power, along with ComEd, into PJM. Id. at 147: 6-12.

5. AEP

21. AEP restates its legal and procedural concerns from its rehearing request, as summarized later in this order.[24] AEP also asserts that eliminating the Companies' T&O rates is not necessary at this time. However, it indicates that it is not wedded to a transactional charge for T&O service as long as there is a method of obtaining a fair contribution from wholesale users of its transmission system through a lost revenue recovery mechanism. AEP seeks dismissal of the instant proceeding for the following reasons.

22. AEP argues that there is no evidence in the record that eliminating its T&O rates would result in the greater efficiency or increased competition assumed by the Commission;[25] instead, a principal impact would be a shift in revenue from AEP's transmission business to generators[26] and other load serving entities. AEP states that transactions are now occurring predominantly from the South and West to North and East directions, and almost all of the available transmission capacity from AEP to PJM has been sold on a firm basis to annual or seasonal customers, at least through the summer of 2004. According to AEP, capacity on AEP's transmission lines into Michigan is essentially fully subscribed during the summer peak periods when there is a substantial demand for imported energy into Michigan. It states that the July 23 Order contains no analysis concerning the determination of whether elimination of the T&O rates would produce more short-term generation efficiencies than transmission and long-term

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[24] AEP also argues that it has not unduly delayed joining an RTO, contrary to the Commission's July 23 Order's implication that it purposefully delayed. AEP asserts that the Commission should resolve its differences with the states regarding RTO development so that AEP can join an RTO.

[25] AEP claims that "free-riding" by wholesale transmission service customers will discourage transmission investment, thereby adversely affecting efficiency in the long term. For example, AEP states it recently upgraded the capability of the interface with Michigan. AEP states that no rational transmission operator would have made the investment in a regime where the users of the upgraded capacity would be able to avoid altogether payment of transmission rates. AEP explains that, where the interfaces are fully subscribed, users should see a price signal that incents the expansion of transmission capacity. When excess capacity is available, AEP believes the current rules incent transmission providers and resellers to discount down to the level of short run marginal costs. See AEP Response at 4-5.

[26] AEP also states that rents will shift among generators if T&O rates are eliminated. Id. at 5.

generation inefficiencies[27] and, whether, and to what extent, the reduced transmission costs will be translated into lower prices for customers.

23. In addition, AEP asserts that, even if the Commission decides to eliminate its T&O rates, there is no reason to eliminate the rates under existing firm transmission service agreements. According to AEP, the costs under those agreements are sunk and should not, therefore, affect efficiency since choices made by the holders of these transmission rights should not be influenced by competing sellers of wholesale power.

24. AEP argues that eliminating T&O rates without providing a revenue-neutral alternative for transmission providers would chill efficient transmission investments and provide erroneous price signals to generators. Further, AEP states that until transmission expansion is planned, a price signal should incent generators to locate new generation on the other side of the constraints.

25. Further, AEP contends that there is no evidence that maintaining the existing T&O rate would preserve any undue competitive advantage for AEP's generation. AEP states that there is no reason why a seller in Midwest ISO or PJM should be disadvantaged in competing for transactions into or through the AEP system. AEP asserts that Midwest ISO had, prior to the issuance of the July 23 Order, decided to discount its "out" transmission rates where necessary to meet competition, and that the July 23 Order removes Midwest ISO and PJM's RTORs for transactions that sink into the other RTO. AEP states that with the elimination of the RTORs, sellers of generation from the Midwest ISO and from AEP into PJM face the same base transmission charges. AEP submits that, similarly, sellers of generation coming from PJM and from AEP into Midwest ISO face the same transmission charges.

26. AEP also claims that eliminating the T&O rates would be discriminatory because T&O customers would not have to pay for use of the transmission system while other customers, including AEP's native load customers, will continue to pay for service on AEP's transmission system. AEP also contends that it would be discriminated against

[27] AEP witness Joe D. Pace questions the economic efficiency arguments underlying the Commission's reasoning for eliminating T&O rates. Mr. Pace states that there are significant impediments to achieving the efficiency gains that the Commission expects, given the high sunk cost and low marginal cost nature of the industry. He states that short-run marginal cost pricing must be implemented consistently and notes that any short-run benefits may be offset by even greater reductions in long-run efficiency unless access charges are established in a non-distorting way and a means of efficiently funding expansions of the network is in place. Moreover, according to Mr. Pace, neither short-run nor long-run efficiencies may materialize unless prices in competing or complementary industries are set in a similar manner. Id., Affidavit of Joe Pace at 6-9.

vis-à-vis RTO members because it would receive the disadvantages of RTO membership without receiving benefits such as centralized transmission planning, shared transmission costs, and the ability to obtain electric power from a much larger geographic area at one flat rate without pancaked transmission rates. AEP also states that the Companies are being discriminated against as compared to other non-RTO member utilities that will be able to continue charging their T&O rates. AEP also faults the July 23 Order as providing no support or rational explanation to justify treating the utilities in the Midwest ISO/PJM footprint differently from those in all the rest of the United States or why the footprint constitutes a "region" for which rate pancaking need be eliminated.[28] Even though AEP believes generally that elimination of T&O rates would be discriminatory, AEP witness Mr. Pace states that under certain conditions, the Commission's policy goals would not be discriminatory.[29]

6. Other Comments

27. Several interested entities state that the Companies are legally obligated to join RTOs as a condition of the Commission's approval of several relevant mergers,[30] and

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[28] For example, AEP points out the inconsistency in the fact that if T&O rates are eliminated as the Commission plans, then transmission from Central Missouri to Hoboken, New Jersey would be essentially free, yet a transaction from Hoboken to Connecticut would bear pancaked charges (i.e., one by PJM and the other by New York ISO). See AEP Response at 32.

[29] Mr. Pace states:

> [T]he only logical and non-discriminatory way to accomplish the Commission's stated objective in this case (creating a common market encompassing the PJM, MISO and former Alliance company areas) is to: (a) eliminate all [T&O] rates of PJM and MISO to each other, as well as to the [Companies]; (b) eliminate the [T&O] rates of all the [Companies] to PJM, MISO and one another; and (c) replace those rates with an alternative revenue recovery system that is as efficient and fair as practical, and applies the same principles of cost recovery to all transmission owners in the new expanded common market.

Id., Affidavit of Joe Pace at 4.

[30] For example, Multiple TDUs state that the Commission's approval of the Ameren-CILCO merger was conditioned upon Ameren and CILCO's commitment to participate in Midwest ISO. See Multiple TDUs Comments at 22. They also state that

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fault the Companies for the subsequent delays in joining RTOs.[31] They assert that, in accepting the Companies' choices, the Commission relied on their express commitments to join RTOs and expected that benefits would quickly accrue. Several entities also advocate eliminating the Companies' T&O rates in order to achieve appropriate scope and configuration within the expanded region.[32]

28. A number of entities support eliminating the Companies' T&O rates on the ground that they obstruct more competitive and efficient electricity markets.[33] For example, Cinergy Services argues that imposing T&O rates between utilities or regions is inefficient because T&O rates constitute artificial "taxes" on power transactions, and

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the Commission relied upon the following Companies' commitments to join RTOs in allowing their mergers and withdrawals: (1) ComEd's commitment to join an RTO when it both allowed the merger that created Exelon and allowed ComEd to withdraw from Midwest ISO; (2) Illinois Power's participation in Midwest ISO as mitigating adverse effects of the merger between Dynegy and Illinova, and Illinois Power's commitment to RTO participation when it allowed Illinois Power to withdraw from Midwest ISO; (3) NIPSCO's commitment to join a Commission-approved RTO within one year of the closing of the Columbia-NiSource merger; (4) AEP's commitment to place all of its eastern and southwestern transmission facilities under market-independent regional control by the end of 2001 when it allowed the AEP-CSW merger. They also state that FirstEnergy is required to join an RTO as a condition of the merger that formed it and state that DP&L is under a statutory obligation to participate in an operational, federally-approved regional transmission entity on January 1, 2001. Id. at 22-23.

[31] See, e.g., AMP-Ohio Comments at 2; Michigan Agencies and City of Hamilton Comments at 4; Cinergy Services Comments at 9; WPSC/UPPCo Initial Comments at 3.

[32] See, e.g., Cinergy Services Comments at 9-14; MDG&E Comments at 4; and Michigan Agencies and City of Hamilton Comments at 4.

[33] See, e.g., Cinergy Services Comments at 14; Michigan Agencies and City of Hamilton Comments at 3; WEPCO/Alliant Initial Comments at 8.

distort the efficiency of power markets.[34] It asserts that T&O rates' inefficiency derives from their design to recover sunk costs, and, consequently, bear no relation to the marginal cost of transmitting power (i.e., congestion costs and transmission losses) which form the basis for efficient generation dispatch. It argues that the same T&O rate applies to every cross-seam transaction regardless of that transaction's cost impact on the transmission system.[35] Further, Midwest ISO TOs state that fairness dictates eliminating the T&O rates of all intervening transmission owners if the Commission is eliminating the Midwest ISO and PJM RTORs because the timely elimination of rate pancaking in the expanded region is critical to achieving competitive and efficient electric markets, which was fundamental to the Commission's acceptance of the Companies' RTO choices.[36]

29. Some entities argue that the Companies are benefiting by continuing to collect access charges for use of their transmission systems[37] while receiving significant

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[34] See, e.g., Cinergy Services Comments, Exhibit 1, Testimony of Michael B. Rosenzweig at 7-8. Mr. Rosenzweig's response to the query of whether his analysis of the Midwest ISO and PJM RTORs also applies to the T&O rates of the Companies, provides in pertinent part:

> Prior to the Commission's order, the MISO through and out rate was an added cost so that the prices of any sales to AEP were higher by the MISO through and out rate of $2.21. Generators not subject to the MISO through and out rate would have been handed a competitive advantage by virtue of the seam: those who could sell profitably at less than $27.21/MWH but not $25/MWH in my example would be able to undercut the MISO generation, even though they would be a less efficient choice economically. The Commission order solved this problem for sales from MISO to AEP but not for sales from MISO to PJM. Sales from MISO to PJM must go through the AEP "tollgate" and pay the AEP through and out rate of $1.42. Generators in PJM whose breakeven price is less than $26.42 but more than $25 still have a competitive advantage over the generator in MISO, even though they are less efficient.

[35] For example, the same T&O rate is applied whether power is being transmitted 50 miles or 1,000 miles and whether a particular power sale increases or alleviates congestion. See Cinergy Services Comments at 16.

[36] See Midwest TOs Comments at 4.

[37] See, e.g., MDG&E Comments at 6; WEPCO/Alliant Comments at 9-10.

transmission cost reductions due to the formation of RTOs in their region[38] and the ensuing competitive advantages.[39] They also assert that, if the Companies' T&O rates are not eliminated, the Commission will not get the benefits that it expects and will reward those entities that avoid RTO membership.[40] For example, Consumers Energy argues that allowing AEP to import power from Midwest ISO and PJM without paying an RTOR while requiring customers in Midwest ISO and PJM to pay AEP's individual T&O rates would reward AEP for failing to fulfill its commitments to join an RTO. Consumers Energy supports eliminating AEP's T&O rates, stating that not doing so would preserve an unfair and unreasonable competitive advantage for AEP's merchant arm. It states that AEP may lose its ability to recover revenues exceeding those approved by regulators, and will likely suffer no resulting cost-based injury.[41] Entities also state

[38] For example, Multiple TDUs argue that the MISO/PJM RTORs should be maintained for transactions to serve the bundled retail load of RTO non-participants, even while the Commission eliminates the MISO/PJM RTORs and the non-participants' T&O rates. They claim that RTO non-participants, such as AEP, have been enjoying the opportunity to obtain significant transmission expense reductions from the de-pancaked rates of utilities in its region that have joined Midwest ISO and PJM. They contend that such benefits should be considered when evaluating non-participants' claims to lost revenue recovery, and that if the RTORs are eliminated for transactions to serve the bundled load of non-participants, this benefit should be credited against any non-participants' allowable lost revenue recovery. See Multiple TDUs Comments at 7-11. As addressed in our companion order in Docket No. EL02-111-000, et al., we deny Multiple TDUs' request to maintain the RTORs for transactions to serve the bundled retail load of RTO non-participants as this would perpetuate significant market inefficiencies.

[39] For example, WEPCO states that the T&O rates act as toll gates that preserve a competitive advantage for RTO non-participants' merchant functions. It asserts that elimination would accelerate at least ComEd's and AEP's compliance with the Commission-stipulated merger conditions to join an RTO. See WEPCO Comments at 6; see also Cinergy Services Comments at 17-18; Multiple TDUs Comments at 4.

[40] In support, Midwest ISO TOs state that there are far more transactions between Midwest ISO and the Companies joining PJM than exist between Midwest ISO and the PJM footprint. See Midwest ISO TOs Comments at 5; see also WEPCO/Alliant Initial Comments at 11-12; Michigan Agencies and City of Hamilton Comments at 7.

[41] Consumers Energy states that AEP's merchant arm would receive the revenue previously allocated to AEP's transmission function, thereby preserving the total revenues of the corporate entity. It asserts that load growth and increased point-to-point

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that it would be unfair for the Commission to eliminate the Midwest ISO/PJM RTORs for transactions within the combined region without simultaneously eliminating the individual T&O rates therein.[42]

30. Ormet, a native load transmission customer of AEP, opposes eliminating AEP's T&O rates. It states that eliminating AEP's T&O rates without a lost revenue recovery mechanism could increase its costs up to $4.4 million dollars annually because the transmission cost-of-service formally paid by T&O service customers would be passed on to native load customers through the rates for network integration transmission service and point-to-point transmission service.[43] Further, Ormet asserts, as AEP is not a member of an RTO, it would not receive the benefits of RTO participation to offset this potential rate increase.

7. Companies' Response to Comments

31. In ComEd and DP&L's joint response to the comments regarding the elimination of the Companies' T&O rates, they state that there is no basis for finding the Companies' T&O rates to be unjust and unreasonable.[44] They contend that parties' comments repeat

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transactions since the test-year underlying AEP's current rates have reduced costs to network customers, including AEP's distribution entities. Noting AEP's assertion that the current rolling-average load ratio share rate for network customers is $1.08 per kW-month, it states that to the extent AEP distribution entities are collecting transmission costs in their rates based upon the approved stated point-to-point transmission rate of $1.42 per kW-month, these entities are likely over-collecting transmission costs from their retail customers. It submits that AEP would likely remain whole by either allocating prior-year revenue over-recoveries of AEP distribution entities to AEP transmission or by increasing the cost responsibility of network customers like AEP distribution entities. See Consumers Energy Answer in Response to AEP at 21-22.

[42] See, e.g., Michigan Agencies and City of Hamilton Comments at 4-5, Midwest ISO TOs Comments at 4; Certain PJM Comments at 3.

[43] See Ormet Comments at 6.

[44] In their response to Cinergy Service's comments, ComEd and DP&L argue that the material presented by Dr. Rosenzweig is insufficient, as demonstrated in the Docket No. EL02-111-000 proceeding, in which he had initially submitted the testimony which is presented here. They state that Dr. Rosenzweig's economic analysis was limited to a

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the Commission's reasoning without adding anything new or substantive to the record. In addition, they argue that those favoring eliminating T&O rates do not acknowledge that elimination of a substantial portion of a utility's revenues, without an alternative lost revenue recovery mechanism, will increase regulatory uncertainty and inhibit transmission development. ComEd and DP&L state that the reasons for the delay in RTO membership cannot be blamed on the Companies as the reasons are complex and involve action by a number of parties including the Commission.[45]

8. Commission Determination

32. Consistent with our responsibility under the FPA to ensure that rates, charges and practices of jurisdictional public utilities are just and reasonable,[46] we find that the rate design for T&O service under the Companies' OATTs is not just and reasonable for transactions sinking in the combined region. Accordingly, we order compliance filings to eliminate the unjust and unreasonable rate design, and establish a new rate design for such T&O service, effective April 1, 2004. This effective date coincides with the effective date for the same new rate design for regional through and out service under the PJM and Midwest ISO OATTs, established in an order on rehearing of the July 23 Order being issued concurrently with this order. This new rate design is transitional in nature and will remain in effect for a two-year period. This new rate design is based on the existing rate and revenues for T&O service, but will recover these revenues from customers in the region in proportion to the benefits such customers will receive from the elimination of the unjust and unreasonable rate design, through a non-bypassable surcharge for delivery to load. This new rate design will eliminate the injurious effects on efficient use of the grid associated with rate pancaking, while mitigating cost shifting among customers and revenue losses that would otherwise occur if rate pancaking were eliminated without a transitional rate mechanism.

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short-run marginal analysis. They argue that, under his theoretical construct, T&O rates anywhere in the country would be unjust and unreasonable and that his analysis fails to adequately balance the pure economic theory with the historic and regulatory setting in which the theory must be applied. They doubt the empirical nature of Dr. Rosenzweig's evidence, stating that it was shown on cross-examination in Docket No. EL02-111-000 to be anything but empirical. See ComEd and DP&L Answer at 4-5.

[45] See ComEd and DP&L Answer at 6.

[46] 16 U.S.C. § 824d (2000); 16 U.S.C. § 824e (2000).

33. A number of the Companies have responded that they are willing to depart from the use of the existing rate design for T&O service, as long as customers using their transmission facilities for T&O service make a fair contribution to the cost of these facilities.[47] The new rate design adopted in this order responds to their concerns. Further, as discussed below, we will adopt their recommendations and allow the existing T&O rate design to remain in effect for existing transactions during a two-year transition period.

34. Some of these Companies, however, expect to transfer or have already transferred operational control of their transmission facilities to an RTO before April 1, 2004; to the extent that their transmission facilities are in an RTO by April 1, 2004, this order will not apply to them. For the other Companies, we have previously initiated an inquiry to explore the impediments to these utilities' implementation of their voluntary commitments to join PJM or Midwest ISO.[48] We expect that they will transfer their facilities to an RTO by the end of the transition period.

35. We are taking the unprecedented action here to eliminate the T&O rates of individual companies that are not yet members of an RTO because of the set of circumstances we face in the Midwest ISO/PJM region. As discussed in more detail below, transmission owners in the Midwest ISO/PJM region have moved forward to establish RTOs in the region to realize the benefits of more efficient and competitive electricity markets. However, given the Companies' location in the heart of the region and their failure to join a RTO, their existing T&O rates leave the region riddled with seams that deny the RTO members the benefits of more efficient and competitive electricity markets and hinders the realization of goals of Order No. 2000. As such the individual company T&O rates are no longer just and reasonable and not unduly discriminatory.

36. As we explained in the July 23 Order and earlier in Order No. 2000, RTOs will eliminate rate pancaking within a region of appropriate scope and configuration, thereby facilitating the realization of competitive and efficient markets.[49] In the July 23 Order, the Commission found that a proper alignment of the Companies can promote more efficient and competitive markets. Some of the Companies, including Illinois Power and New PJM Cos., are located between two functioning RTOs in the region and have close

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[47] See AEP Response at 6; Ameren Response at 10; NIPSCO Response at 5.

[48] See New PJM Companies, et al., 104 FERC ¶ 61,274 (2003).

[49] See July 23 Order, 104 FERCat P 29; Order No. 2000 at 31,024, 31,082-84, 31,174-75.

links with their neighboring utilities in the Midwest ISO. Specifically, some Companies are located in the heart of the common market that those RTOs and their members seek to achieve, [50] and significantly "island" Michigan and Wisconsin from the remainder of the Midwest ISO. The Commission recognized the Companies' unique position vis-à-vis the Midwest ISO and PJM when it approved their status as RTOs. The Commission conditioned its approval of Midwest ISO and PJM as RTOs on their attaining sufficient scope and configuration to meet the requirements of Order No. 2000. With respect to Midwest ISO, the Commission found that Midwest ISO's configuration problem along its eastern border would be solved by the successful integration of some or all of the Companies into the Midwest ISO.[51] Likewise, after finding that PJM exhibited insufficient scope to meet the requirements of Order No. 2000, on rehearing, the Commission found that PJM's planned expansion to incorporate some of the former Alliance Companies alleviated concerns regarding scope and configuration.[52]

37. Subsequently, the Companies decided to join either Midwest ISO or PJM. However, the choices of the Companies produced unjust and unreasonable rates, terms and conditions of transmission service. The Commission could, therefore, only accept the RTO choices of the Companies subject to several conditions, including, as particularly relevant here, the resolution of pancaked T&O rates[53] and the creation of a common market across the proposed Midwest ISO/PJM region. These conditions mitigated the adverse effects of the seams resulting from certain of the Companies' RTO choices so that the seams did not obstruct the attainment of efficient and competitive

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[50] We have previously noted the close links among the individual companies and between the individual companies and neighboring RTOs. July 23 Order, 104 FERC at P 33; Alliance Companies, et al., 103 FERC ¶ 61,274 at P 27-30 (2003).

[51] Midwest Independent Transmission System Operator, Inc., 97 FERC 61,326, order on reh'g, 103 FERC ¶ 61,169 (2001).

[52] See PJM Interconnection, LLC, et al., 96 FERC ¶ 61,061 (2001), order on reh'g, 101 FERC ¶ 61,345 (2002).

[53] The timely elimination of rate pancaking in the Midwest ISO/PJM region, which is critical to achieving competitive and efficient electric markets, was fundamental to our decision to accept the Companies' RTO choices. See Alliance Companies, et al., 103 FERC ¶ 61,274 (2003).

markets in the region.[54] In conditionally accepting the Companies' RTO choices more than a year ago, the Commission relied upon their express intentions and commitments to join the RTOs they had chosen, so that, by acting expeditiously in allowing each company to proceed to join the RTO of its choosing, those choices would be implemented, and the resulting benefits would be quickly realized. However, most of the Companies still have not joined an RTO, leaving the region riddled with seams with pancaked individual-company T&O rates.[55] Given their location and the close links between the Companies and the neighboring RTOs, the T&O rates of these RTO non-participants contribute to seams in the heart of the Midwest ISO/PJM region. Their continuing lack of participation in a RTO prevents the realization of more efficient and competitive markets, and the attainment of the goals of Order No. 2000, by RTO members in the region.[56]

38. While we recognize that the Companies have taken many steps towards joining a RTO, their progress is insufficient for turning over their facilities to an operational RTO. Therefore, the Commission previously initiated a proceeding to work with the Companies to help resolve the obstacles that they face in turning over their facilities to a RTO.[57] Our action here assures that more efficient and competitive markets can be realized in the meantime.

39. The evidence in the record demonstrates that eliminating the T&O rates would improve efficiency. In the investigation in Docket No. EL02-111-000, witnesses such as Michael B. Rosenzweig, of Coalition Against Seams, showed that T&O rates are inherently inefficient. Additionally, Mr. Rosenzweig presented an analysis that demonstrated that T&O rates adversely affect trade within the proposed Midwest ISO/

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[54] See July 23 Order at P 32-35. In the July 23 Order, the Commission characterized rate pancaking across the seam of these two RTOs as "intra-RTO" rate pancaking and prohibited under Order No. 2000 because Order No. 2000 requires that RTOs eliminate rate pancaking over a region of appropriate scope and configuration. July 23 Order at P 35.

[55] As discussed in our companion order in Docket No. EL02-111-000, et al., this is one of a series of Commission orders, including the July 23 Order, that document the problems of RTO scope and configuration in this region.

[56] As the Midwest ISO TOs note, there are far more transactions between the Midwest ISO and the Companies joining PJM than there are between the Midwest ISO and the existing PJM footprint. See Midwest ISO TOs Comments at 5.

[57] See New PJM Companies, 104 FERC ¶ 61,274 (2003).

PJM footprint.[58] For example, Mr. Rosenzweig stated that, based on his review of transmission service requests, exports from Midwest ISO fell dramatically in the month that Midwest ISO began operations and only began to increase when Midwest ISO began discounting the RTOR.[59] As we noted in the July 23 Order, only four parties in the proceeding in Docket No. EL02-111-000 objected to the elimination of the regional T&O rates at issue in that proceeding. However, even certain of these parties recognized the inefficiencies related to the T&O rates and the benefits of eliminating them.[60]

40. As for the specific concerns raised in this proceeding, we disagree with AEP that limited available transmission capacity on its system will limit the benefits of eliminating its T&O rates. AEP argues that its capacity into PJM is already sold on a firm basis through the summer of 2004, and with the elimination of rate pancaking on the seams, only capacity made available after the summer of 2004 could be used to access subsequently available for more efficient generation. However, AEP also acknowledges that it did not do an analysis of the extent to which some of its capacity into PJM might be available for short-term transactions as hourly conditions evolve.[61] Further, if AEP's capacity into Michigan is typically subscribed during the summer peak period and expected to be fully subscribed next summer, by eliminating rate pancaking effective April 1, 2004, customers may be able to make more efficient transactions next summer than they would if we delayed elimination of rate pancaking.[62] Additionally, off-peak periods in the summer and in other periods would still be available for more efficient transactions.

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[58] Mr. Rosenzweig included evidence of financial harm caused by the existence of the T&O rates in the region. See Cinergy Services Comments, Exhibit No. CIN-2 at 13-18.

[59] Mr. Rosenzweig added that, despite the discounts in the Midwest ISO RTOR, the level of export service never returned to the level that prevailed before the Midwest ISO began operations. See Cinergy Services Comments, Exhibit No. CIN-2 at 5.

[60] In the proceeding in Docket No. EL02-111, a witness for companies joining PJM recognized that elimination of rate pancaking would represent an improvement. Tr. at 185. Additionally, existing PJM companies also recognized that T&O rates are inefficient and should be eliminated when a common market is implemented. See Exhibit No. Certain Classic PJM TOs-1 at 24.

[61] See AEP Response, Exhibit No. JCB-1 at 9-11.

[62] For example, if Michigan load currently imports power from AEP and pays the AEP T&O rate, with the elimination of the Companies' T&O rates, they might be able to import more efficient power from other companies within the proposed Midwest ISO/PJM region.

41. We also disagree with AEP that the T&O rates provide useful price signals. Rates that reflect embedded transmission costs on a transactional basis, as the T&O rates do, can have distorting effects on economic choices. Therefore, rates to recover embedded costs must be re-designed carefully to avoid such effects. As discussed above, the Companies' T&O rates prevent efficient economic choices, and, given the Companies' location, the T&O rates must be replaced with a more efficient methodology for pricing T&O service.

42. With respect to AEP's argument that elimination of T&O rates will shift rents among generators, we expect rents to shift among generators due to the elimination of rate pancaking, but we do not expect such rent-shifting to happen indiscriminately. We expect rents to shift from the inefficient generators to the efficient generators to reflect the increase in efficiency in the proposed Midwest ISO/PJM footprint from the elimination of the T&O rates in the region.

43. AEP states that, as a result of our July 23 Order, its generation and Midwest ISO generation pay the same transmission rate to sell power to load in the existing PJM footprint, and therefore, AEP's generation does not have a competitive advantage over other generation. AEP is correct that our July 23 Order when implemented would eliminate the adverse effects of rate pancaking between PJM and Midwest ISO. The elimination of rate pancaking for transactions between the two RTOs helps promote efficiency and competition and eliminate some of the undue competitive advantages that certain power sellers, such as the Companies' merchant interests, have vis-à-vis other generators for certain transactions; however, given the unique positioning of the Companies between the two RTOs and their failure to date to join RTOs, there remain many more seams in the proposed Midwest ISO/PJM region beyond the seams among PJM, AEP and Midwest ISO.

44. The seams among the individual Companies and between the Companies and the RTOs continue to provide them with undue competitive advantages. For example, ComEd's T&O rates limit the exports into AEP, protecting AEP's generation. That is, these seams and the pancaking of T&O rates on these seams protect the Companies' generation from competitive markets in the region. Therefore, they must be eliminated. In addition, while the Commission may be able to limit some of the undue competitive advantage of a particular company's generation for certain transactions by eliminating rate pancaking between PJM and Midwest ISO, promoting efficiency and competition, let alone equity and fairness, requires the removal of all rate pancaking in the combined region to mitigate the effects of the seams within the region.

45. Moreover, absent our action here, the Companies that have not joined an RTO will be able to take advantage of the elimination of pancaked rates in their neighboring RTOs while denying reciprocal benefits to other transmission owners that have successfully

pursued RTO formation. Permitting the Companies to benefit in this way vis-à-vis other transmission owners that are in an RTO is not only inequitable, but it also gives the wrong incentives; namely, it unfairly disadvantages those transmission owners that are in RTOs and rewards those transmission owners that have not joined an RTO. As we stated earlier, AEP is able to import electric power over the transmission systems of each RTO without paying pancaked rates to wheel over the system of each individual transmission owner in each RTO.[63] Therefore, our action here also does not unduly disadvantage AEP relative to RTO participants.[64] Further, we remain concerned by the length of time that has transpired since several of the Companies committed to join RTOs as part of their merger proceedings; elimination of rate pancaking for T&O service over their facilities is one step towards achieving the regional benefits that would accrue had they fulfilled their voluntary RTO commitments.

46. As discussed above, we find that the rate design for T&O service under the Companies' individual OATTs, when applied to transactions sinking anywhere within the combined region, is unjust and unreasonable and must be eliminated.[65] We will eliminate it effective April 1, 2004, to coincide with the elimination of the existing rate design for T&O service under the Midwest ISO and PJM OATTs in our order on rehearing of the July 23 Order, which is being issued concurrently with this order, and to allow sufficient time to implement a new rate design for T&O service, as discussed below. However, initially, during the two-year transition period, we will eliminate the existing rate design only for new transactions; the existing rate design will not be eliminated for those transactions existing as of April 1, 2004, under the Companies' OATTs until the end of the transition period. As AEP states, there would be little efficiency benefit to eliminating the existing rate design for existing firm transmission service reservations.

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[63] Multiple TDUs are correct that, absent our action here today, AEP could have been required to pay non-pancaked rates for transmission service over the individual transmission systems in the Midwest ISO and PJM which would exceed the corresponding Midwest ISO and PJM RTOR. See Order No. 2000 at 31,180; GridFlorida LLC, et al., 94 FERC ¶ 61,363 at 62,337 (2001).

[64] Some of the other problems that AEP raises with respect to elimination of the individual company T&O rates can be easily remedied in the compliance filings that we are directing in this order. For example, there will be no subsidization of wholesale transmission service customers by shareholders and other customers that pay for transmission service, and no disincentives to transmission investment because of "free-riders," if AEP were to file a mechanism to recover lost revenues.

[65] AEP is correct that the July 23 Order did not require the filing of cost support. See AEP Response at 41. The issue before us is a change in rate design that will improve the efficiency and competitive markets in the proposed Midwest ISO/PJM region.

The transmission costs associated with such transactions are sunk and will have little effect on the power purchase and sales decisions of the holders of those transmission rights. Eliminating the existing rate design for T&O service only for new transactions will minimize lost revenues to be recovered under the new transitional rate design.

47. Accordingly, we will direct compliance filings within 45 days of this order to eliminate the existing T&O rates, as discussed above, and to implement a new transitional rate design, as discussed below, effective April 1, 2004.

C. Lost Revenue Recovery Mechanism

1. Superseding Rate Design for T&O Service

48. The July 23 Order did not reach the issue of a lost revenue recovery mechanism since it only initiated a Section 206 investigation into the Companies' individual T&O rates. However, the Companies raise similar concerns regarding recovery of revenues lost as a result of the elimination of their T&O rates as they raise in Docket No. EL02-111 with respect to the elimination of the RTORs.[66] As indicated in their individual responses to the investigation, the Companies support the adoption of a lost revenue recovery mechanism if their T&O rates are eliminated. For example, Ameren is willing to waive its T&O rates if a lost revenue recovery mechanism is put in place simultaneously. In addition, AEP states that it is not wedded to its T&O rate design if a transitional rate mechanism is in put in place to recover lost revenues.

49. On the other hand, Multiple TDUs and Detroit Edison contend that non-RTO member transmission owners should not be eligible for lost revenue recovery mechanisms if they are not participating in an RTO.[67] Multiple TDUs assert that AEP in particular, because of the substantial uncertainty surrounding its RTO participation, is not entitled to a lost revenue recovery mechanism before it joins an RTO because such mechanisms were intended to maintain the revenue neutrality for entities when they

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[66] See, e.g., Ameren Response at 8-9 ; AEP Response at 15, DP&L Response at 14; see also order in Docket No. EL02-111-004, et al, being issued concurrently with this order.

[67] See Multiple TDUs' Comments at 10, Detroit Edison Answer to New PJM's Motion for Expedited Clarification at 5.

joined an RTO.[68] Multiple TDUs state that utilities like AEP should not be able to recover lost revenues because they are late in fulfilling legal obligations to join an RTO. They claim that the receipt of T&O service revenues and market advantages from the continuation of rate pancaking, after the date when they should have joined an RTO, should be counted as a sufficient transitional mechanism. We disagree. We find that the Companies have raised valid concerns about the recovery of lost revenues and about resulting cost shifts that would occur upon the elimination of the T&O rates without simultaneously replacing them with a lost revenue recovery mechanism.

50. Transitional lost revenue recovery mechanisms, if properly structured, can serve as a reasonable transition mechanism to address revenue losses resulting from the elimination of rate pancaking. By recovering lost revenues from load on each system proportionate to the benefit that the load receives from the elimination of rate pancaking, and recovering such costs through a non-bypassable surcharge for delivery within the system, such transitional lost revenue recovery mechanisms better control cost-shifting than conventional license plate rates without transitional surcharges while simultaneously avoiding the injurious effects on efficient use of the grid associated with rate pancaking.[69]

51. In this proceeding, as well as in the order in Docket No. EL02-111-004, et al., being issued concurrently with this order, we find it necessary to move forward to establish a lost revenue recovery mechanism to replace the T&O rates when they are eliminated. By fixing the superseding rate in this Section 206 proceeding, the Commission will mitigate cost shifting during the transition period and ensure just and reasonable rates upon the elimination of the T&O rates.

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[68] Multiple TDUs contend that AEP's shareholders have continued to enjoy the benefits of AEP's merger with CSW while the principal customer-oriented merger condition, RTO participation, has remained unfulfilled. They assert that it may be appropriate to place part of the burden of any revenue shortfall resulting from T&O rate elimination on AEP's shareholders. Detroit Edison would assess the cost responsibility for revenue shortfall on the local customers of the non-RTO member transmission owner. See Multiple TDUs' Comments at 8-9.

[69] Native load customers are ultimately responsible for the costs of the utilities' transmission system. Historically, revenues for T&O service have offset part of the cost of the transmission system that otherwise would be paid by native load. The transitional lost revenue recovery mechanism will prevent the transmission rates for native load from increasing as a result of the elimination of rate pancaking, thereby preventing cost-shifting from T&O service customers to native load.

2. Cost-of-service Requirement

52. The July 23 Order found that the RTO members need not file updated cost-of-service studies to support proposals to recover revenues lost due to the elimination of the RTORs.

53. New PJM Cos. request clarification as to whether non-RTO members must file cost-of-service updates to support proposals to recover lost revenues and if they must further demonstrate that lost revenue recovery will not result in an over-recovery of their updated revenue requirement.

54. Illinois Power incorporates New PJM Cos.' clarification request and also specifically urges against a cost-of-service requirement for non-RTO members to recover revenues lost due to the elimination of T&O rates. Illinois Power states that should the Commission eliminate its T&O rates, it is essentially imposing a rate structure in the region as if all the Companies were in an RTO. It states that the elimination of the T&O rates would result in a single charge for any delivery within the Midwest ISO/PJM footprint, regardless of the RTO membership status of individual utilities within the footprint. It concludes that there is no valid basis to impose upon non-RTO members a different standard for justifying lost revenue recovery.[70]

55. Opposing entities assert that any non-RTO members' proposals for lost revenue recovery or increased rates must be justified by complete cost-of-service updates.[71] They state that the exemption from this requirement should be inapplicable to non-RTO members, whom they argue should not benefit from this policy before they become RTO members.[72] Multiple TDUs also support requiring non-RTO members seeking a lost revenue recovery mechanism to also demonstrate that they would otherwise be deprived of the ability to recover their cost-of-service due to the elimination of rate pancaking.[73]

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[70] See Illinois Power Motion in Support of New PJM at 3-4.

[71] See Consumers Energy Answer in Opposition to New PJM at 7-8; Detroit Edison Answer to New PJM at 3-4; Wisconsin Electric Answer to New PJM at 9; Michigan Agencies Opposition to New PJM at 6-8 and Application for Rehearing and Motion at 5-11.

[72] See Michigan Agencies' Opposition to New PJM at 8; Wisconsin Electric Answer to New PJM at 10-11.

[73] Multiple TDUs state that a non-cost-based filing for pancake-replacement surcharges amounts to an innovative rate filing under 18 C.F.R. § 35.34(e), and the associated rate impacts must be quantified and subjected to a cost-benefit evaluation.

56. AEP provides a limited cost-of-service analysis in support of its current T&O service revenue level. It claims that its existing rates are cost justifiedand that without its T&O service revenue, it would under recover its cost-of-service by nearly one-third. It further claims that passing this revenue shortfall onto its network customers would yield nearly a 25 percent rate increase.[74]

57. The July 23 Order made it clear that RTO members would not be required to provide updated cost-of-service information in order to file for a transitional lost revenue recovery mechanism. However, the July 23 Order did not decide whether the requirement would be imposed on non-RTO members. In prior rulings, we have not required RTO members to file an updated complete cost-of-service to justify transitional surcharges to recover lost revenues resulting from the elimination of rate pancaking, as doing so would create an unnecessary impediment to RTO formation.[75] Here, that concern is not implicated in our elimination of non-RTO members' T&O rates. However, given that we are eliminating all T&O rates within the proposed Midwest ISO/PJM region, we believe it is necessary to provide both RTOs and the individual former Alliance Companies with an equitable opportunity to recover lost revenues on a transitional basis. Therefore, we clarify that we will not require non-RTO members to make cost-of-service filings as a prerequisite to lost revenue recovery. We have previously accepted the existing rates of these companies as just and reasonable and the Section 206 investigation in this proceeding focuses on the design of the rates for T&O service, not the level of those rates. The new rate design being implemented in this proceeding will merely change the form of those rates while maintaining the revenues produced by the existing rates.[76]

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[74] See AEP Response at 42.

[75] See Alliance Companies, et al., 94 FERC ¶ 61,070, reh'g denied, 95 FERC ¶ (2001); Alliance Companies, et al., 99 FERC ¶ 61,105 at 61, 446 (2002); PJM Interconnection L.L.C. and Allegheny Power, 96 FERC ¶ 61,060 (2001).

[76] In addition, the Commission continues to monitor and review regulated rates to ensure that they remain reasonable. To that end, the Commission recently proposed to revise its regulations by establishing quarterly financial requirements and make changes to the existing FERC Annual Reports to help in achieving the goal of vigilant oversight by providing the Commission with more timely, relevant, reliable and understandable financial information. This additional financial reporting will aid the Commission in, among other things, assessing the economic consequences of transactions and evaluating the adequacy of existing traditional cost-based rates.

3. Specific Attributes of Lost Revenue Recovery Mechanism

58. Several parties request clarification regarding the July 23 Order's determination that lost revenue recovery mechanisms should be based on a test period consisting of the most recent 12 months for which data are available. Certain parties express opposition to using the most recent 12 months as the test period for any proposed lost revenue recovery mechanism, and propose alternative time periods such as the most recent calendar year[77] and data from test year 2001.[78] Parties also express reservations about relying on NERC tag data to develop lost transmission revenues without a hearing.[79]

59. We refer parties to our order in Docket No. EL02-111-004, et al., being issued concurrently with this order, in which we make findings with respect to appropriate transitional lost revenue recovery mechanisms and direct Midwest ISO and PJM to submit, through compliance filings, lost revenue recovery surcharges to be implemented simultaneously with the elimination of their RTORs. Similarly, here we will direct the Companies to file compliance filings, consistent with the SECA mechanism that we prescribe in our order in Docket No. EL02-111-004, et al. The surcharges would be simultaneously implemented with the elimination of the Companies' T&O rates, effective April 1, 2004, and remain in effect for a two-year period. We will direct the Companies to submit compliance filings within 45 days of the date of this order that provide the Commission with the lost revenue recovery charges calculated pursuant to the methodology prescribed in the order in Docket No. EL02-111-004, et al. The Companies should also provide all supporting documents containing all calculations and data, including NERC tag data. We expect the parties in the region to work cooperatively in the preparation of these filings, and encourage them to attempt to resolve issues before the filings are made.

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[77] See, e.g., New PJM Motion at 6, GridAmerica Motion 11.

[78] See Midwest ISO TOs' Request for Rehearing and Clarification at 32. They state that use of data after the year 2001 is not reasonable with respect to Midwest ISO TOs as it creates significant problems because such data is aberrational with the start-up of Midwest ISO in 2002 and would create under-recoveries. Id.

[79] See, e.g., Certain PJM Cos. Answer in Opposition to New PJM at 11; State of Michigan and MPSC Rehearing/Clarification Request at 7-8.

D. Rehearing Requests

1. FPA Section 206

60. On rehearing, a number of the entities contend that the Commission's initiation of the Section 206 proceeding in Docket No. EL03-212-000 violated the requirements of FPA Section 206.[80] They argue that the Commission has not met its burden to make a prima facie case for its FPA Section 206 proceeding as there is insufficient evidence to support initiating this proceeding.[81] Certain entities refer to the record in Docket No. EL02-111-000 as lacking evidence supporting the elimination of individual company rates. In addition, they assert that eliminating the T&O rates without establishing a replacement lost revenue recovery mechanism would violate FPA Section 206 and would amount to an unlawful taking in which companies would be deprived of the opportunity to earn a return on their investment in regulated assets. For the same reason, they oppose a refund effective date of October 4, 2003, which they support changing to November 1, 2003, the date set by the July 23 Order for the elimination of Midwest ISO/PJM RTORs and the date which the July 23 Order contemplates for the commencement of recovery of lost revenues. They argue that the earlier October 4, 2003 refund effective date would leave them without a way to recover revenues lost upon the elimination of their T&O rates.

61. A number of entities also argue that the July 23 Order seeks to impermissibly shift the Commission's burden under Section 206 of the FPA to the subject companies to make FPA Section 205 filings to recover revenue losses, which they assert would not practically implement a regional SECA-type solution.[82] They state that, alternatively, they would have to attempt to recover lost revenues from their native load customers or force their shareholders to absorb the losses.

62. Certain entities raise other concerns. They argue that the July 23 Order gave inadequate notice regarding their T&O rates or how they would be changed, thus limiting their ability to respond to the July 23 Order.[83] Some entities also object to the paper hearing established by the July 23 Order, arguing that it is inadequate to address the

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[80] See, e.g., AEP Rehearing at 11; ComEd Rehearing at 7; DP&L Rehearing at 10.

[81] See, e.g., Illinois Power Rehearing at 11.

[82] See, e.g., ComEd Rehearing at 12; Illinois Power Rehearing at 14; DP&L Rehearing at 12.

[83] See, e.g., AEP Rehearing at 18 and Illinois Power Rehearing at 12.

issues in this proceeding.[84] For example, GridAmerica states that the July 23 Order failed to give adequate time and guidance for a meaningful response.

2. FPA Section 202(a) and Order No. 2000

63. Several entities argue that the Commission is attempting to compel Companies' participation in an inter-regional coordination arrangement, in violation of Order No. 2000[85] and inconsistent with FPA Section 202(a).[86] They assert that Order No. 2000 only provides for voluntary participation in RTOs and that FPA Section 202(a) gave the Commission the ability to encourage, but not compel, the interconnection and coordination of transmission facilities. They contend that the Commission is doing indirectly, through the elimination of T&O charges for deliveries to those RTOs, what it cannot do directly.

3. Commission Response

64. As discussed above, we are eliminating the Companies' T&O rates, effective April 1, 2004, simultaneously with the implementation of a new transitional rate design for T&O service. We are not ordering refunds here. Thus, our actions in this proceeding moot concerns with recovering lost revenue in the context of the October 4, 2003 refund effective date established in this investigation.

65. With respect to their procedural concerns, the July 23 Order gave adequate notice that the T&O rates under their individual-company OATTs were expressly at issue in this proceeding and provided the Companies with adequate opportunity to file in response. In addition, as discussed above, we are not attempting to compel RTO participation as we are taking action to ensure just and reasonable rates in these circumstances.

66. The Companies have also requested rehearing concerning various issues regarding recovery of lost revenues in the event that the Commission finds their T&O rates unjust

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[84] See, e.g., AEP at 15; GridAmerica at 18; Pennsylvania Commission at 8.

[85] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,089 at 31,074 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), aff'd sub nom. Public Utility District No. 1 of Snohomish County Washington, et al. v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[86] 16 U.S.C. § 824(a) (2000); see, e.g., AEP Rehearing at 20; DP&L Rehearing at 20; ComEd Rehearing at 9.

and unreasonable. We will deny these requests for rehearing, as the July 23 Order made no determination concerning the justness and reasonableness of the Companies' T&O rates or the recovery of lost revenues.

The Commission orders:

(A) The requests for rehearing are hereby denied, as discussed in the body of this order.

(B) The through and out rates under the OATTs of AEP, Ameren, ComEd, Illinois Power, and DP&L for transactions sinking within the combined region (Midwest ISO, PJM and Companies' footprints) are hereby eliminated effective April 1, 2004, as discussed in the body of this order.

(C) Companies are directed to make compliance filings, as discussed in the body of this order, within 45 days of the date of issuance of this order.

(D) ATSI and NIPSCO are hereby dismissed from this proceeding, as discussed in the body of this order.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

Appendix A
Docket No. EL03-212-000, et al.
Timely Motions to Intervene and Notices of Intervention

Allegheny Power and Wolverine Power Supply Cooperative, Inc.
American Municipal Power, Inc. of Ohio (AMP-Ohio)
Baltimore Gas and Electric Company
Blue Ridge Power Agency
Buckeye Power, Inc.
Cinergy Services, Inc. on behalf of The Cincinnati Gas & Electric Co.; PSI Energy, Inc. and Union Light, Heat and Power Co. (Cinergy Services)
Cities of Dowagiac and Sturgis, Michigan
City of Hamilton, OH (City of Hamilton)
Coalition of Municipal and Cooperative Users of New PJM Cos.
Consumers Energy Co. (Consumers Energy) and Illinois Cities
Dairyland Power Cooperative
Detroit Edison Co. (Detroit Edison)
Duke Energy Corporation
Duke Energy North American, LLC
Edison Mission Energy, Edison Mission Marketing and Trading, and Midwest Generation EME, LLC
Illinois Commerce Commission
Illinois Municipal Electric Agency and Indiana Municipal Power Agency, (collectively, Muni-Coop Coalition)
International Transmission Co.
Madison Gas & Electric Co. (MDG&E)
Maryland People's Counsel Office, Wabash Valley Power Assoc. Inc., and Illinois Commerce Commission
Maryland Public Service Commission
Michigan Public Power Agency and Michigan South Central Power Agency (collectively, Michigan Agencies)
MidAmerican Energy Co.
Midwest Independent Transmission System Operator (Midwest ISO)
Midwest ISO Transmission Owners (Midwest ISO TOs), including: Alliant Energy Corporate Services, on behalf of Interstate Power and Light Company (f/k/a IES Utilities Inc. and Interstate Power Company); Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; LG&E Energy Corporation on behalf of Louisville Gas and Electric Co. and Kentucky Utilities Co.; Lincoln Electric System; Minnesota Power (and its subsidiary Superior Water L&P); Montana-Dakota Utilities Company; Northern States Power Company, subsidiaries of Xcel Energy, Inc.; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana);Wabash Valley Power Association, Inc.

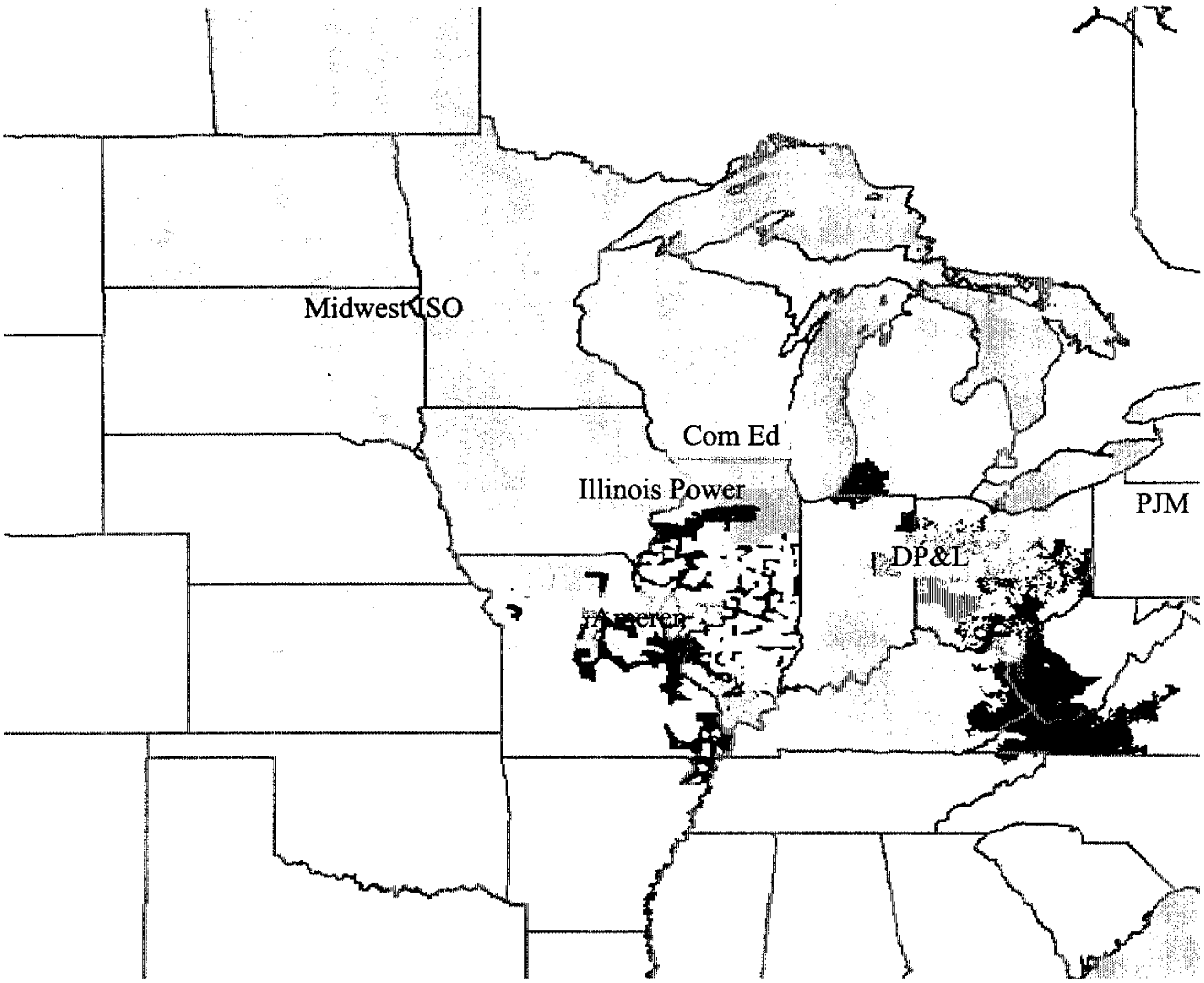
Nordic Marketing, LLC
Ohio Public Utilities Commission
Ormet Primary Aluminum Group (Ormet)
PJM Industrial Customer Coalition and Coalition of Midwest Transmission Customers
PPL Electric Utilities Corp. and PPL Energy Plus, LLC
PSEG Companies
Public Service Commission of Wisconsin
Rockland Electric Co.
Southeast Michigan Systems
Virginia Electric and Power Company
Wabash Valley Power Association, Inc.
Wisconsin Electric Power Company (Wisconsin Electric)
Wisconsin Public Power, Inc.

Docket No. EL03-212-000
Late Motions to Intervene

Alliant Energy Corporate Services, Inc. (Alliant)
Constellation NewEnergy, Inc.
Duke Energy Corp.
Grid America LLC
Michigan Electric Transmission Co., LLC
North Carolina Electric Membership Corp.
Pennsylvania Office of Consumer Advocates
Pepco Holdings, et al.
State of Michigan and the Michigan Public Service Commission
Steel Dynamics, Inc.

Docket Nos. EL03-212-000
and EL03-212-001

Appendix B
Docket No. EL03-212-000, et al.
The Five Former Alliance Companies that have not yet joined either PJM or Midwest ISO.



Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 4 of the Direct Testimony and Exhibits on Rehearing of J. Craig Baker ("Baker Testimony"), lines 11-15.

Provide a summary of the current status of this issue.

RESPONSE

The November 17, 2003 FERC Orders in Docket Nos. EL02-111 and EL03-212 directed the affected transmission service providers, AEP included, to make compliance filings by January 2, 2004 to modify their open access transmission tariffs (OATT), effective April 1, 2004, to eliminate transaction-based charges for certain out-and-through transmission services, and implement load-based charges (aka, "SECA") to collect the revenues that would otherwise be lost. Since those Orders were issued, the FERC has clarified, on December 10, 2003, the Commission's intent regarding "existing transactions" that will continue to be charged the out-and-through rates, and has twice extended the time for filing of the SECA rates, first until January 30 and then until February 13, 2004. The Commission has also implemented Settlement Judge procedures, and a meeting of all affected parties/stakeholders before the Chief Judge was held on February 3, 2004. In the time since November 17, 2003 the transmission providers and transmission owners have held many meetings (including stakeholder meetings) in an attempt to develop consensus proposals for compliance with the November 17 Orders.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 4 of the Direct Testimony and Exhibits on Rehearing of J. Craig Baker ("Baker Testimony"), lines 11-15.

Provide a summary of American Electric Power's ("AEP") position on this issue.

RESPONSE

The November 17, 2003 Orders in FERC Docket Nos. EL02-111 and EL03-212 were very much in-line with recommendations that AEP had made in its comments and pleadings before the FERC in the Dockets. AEP had maintained that if the Commission were to find that the out-and-through rates should be eliminated for transactions in the combined MISO/PJM region, then it would be essential for the Commission to protect AEP's customers from the significant cost shifting that would result from the loss of transmission service revenues. AEP recommended the implementation of SECA charges for a period of at least two years, followed by the implementation of a new rate design that will fairly charge all transmission users in the region based on the costs of service and their use of the system.

WITNESS: J Craig Baker

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Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 5 of the Baker testimony, lines 4-7.

Identify the estimated annual energy, in terms of MWh, for each year of the study period that is provided pursuant to bilateral contract.

RESPONSE

The CERA analysis did not explicitly model bilateral contracts for commitment and dispatch purposes. However, in the post-processing analysis, Unit Power of 259 MW from Rockport was directly allocated to Carolina Power and Light. Besides this exception, no other attempt was made to differentiate between bilateral contracts and sales into the PJM market. The difference between the AEP system's operating companies' internal requirements and the total resources was treated as "system sales" volume.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 5 of the Baker testimony, lines 4-7.

Identify AEP's total estimated energy output for each year of the study period.

RESPONSE

AEP's estimated output from the CERA study results for the AEP owned fossil, nuclear, and hydro generation as well as AEP's OVEC generation share is shown in the attached Exhibit.

WITNESS: J Craig Baker

Estimated Energy Output (Sources)

Study Period 2004-2008

(' 000 MWh)

CASE I - "AEP IN PJM"

Sources	2004 Forecasted	2005 Forecasted	2006 Forecasted	2007 Forecasted	2008 Forecasted
Own Fossil Generation	133,172	134,457	135,109	136,115	136,915
Nuclear Generation	17,173	17,144	17,115	17,150	17,165
OVEC Purchases	6,385	6,470	6,554	6,630	6,705
Hydro	656	626	594	599	564
Total	157,386	158,697	159,372	160,494	161,349

CASE II - "AEP Stand-Alone"

Sources	2004 Forecasted	2005 Forecasted	2006 Forecasted	2007 Forecasted	2008 Forecasted
Own Fossil Generation	122,175	123,993	125,812	127,525	128,968
Nuclear Generation	17,173	17,144	17,115	17,140	17,165
OVEC Purchases	5,566	5,831	6,096	6,269	6,441
Hydro	657	625	592	574	556
Total	145,571	147,593	149,615	151,508	153,130

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 5 of the Baker testimony, lines 4-7.

Is the difference between (a) and (b) above the amount of energy that would be offered for sale in spot markets? If not, explain.

RESPONSE

The difference between (a) and (b) and after reducing the energy supply to meet the AEP System internal load requirements, equals the amount of energy available to offer for sale in the spot market.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 5 of the Baker testimony, lines 4-7.

Explain how prices and/or cost of energy provided under bilateral contracts would affect Locational Marginal Prices ("LMP").

RESPONSE

AEP has not analyzed the impact of bilateral contracts on LMPs.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 5 of the Baker testimony, lines 4-7.

Does any scenario of the cost-benefit studies provided by Cambridge Energy Research Associates ("CERA") to AEP assume that energy provided under bilateral contracts would be offered on the spot market? If so, explain why this is a reasonable assumption.

RESPONSE

Please see the response to Item No. 2a.

WITNESS: J Craig Baker

3

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 5 of the Baker Testimony.

Explain why 5 years was selected as the period covered in the study conducted by AEP and CERA to evaluate the costs and benefits related to AEP joining PJM Interconnection LLC ("PJM")

RESPONSE

Because no study period was specified by the Commission, AEP believed that five years was a reasonable period to provide an adequate evaluation of cost/benefit of joining PJM, as well as to expedite the study for filing with the Commission.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 5 of the Baker Testimony.

Explain why AEP selected CERA to conduct the study rather than selecting another firm or performing the study itself.

RESPONSE

CERA was selected to conduct the AEP cost/benefit study of joining PJM because of their reputation as a leader in providing independent analysis regarding interconnected system and energy related issues. Additionally, CERA was already conducting a multi-client study entitled *Grounded In Reality* to assess transmission bottlenecks in the country and to find cost-effective solutions for them. Therefore, CERA had already developed a GE-MAPS model that could be used as a starting point with appropriate modifications for expediting this study in a cost effective and timely manner.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 5 of the Baker Testimony.

Provide the cost AEP has incurred and expects to incur as a result of employing CERA to conduct the study.

RESPONSE

AEP has incurred out-of-pocket expenses of about $200,000 and expects to incur approximately $25,000 additional out-of-pocket cost as a result of employing CERA to conduct the study.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 5 of the Baker Testimony.

Explain how AEP intends to account for the cost of the study and how it intends to allocate this cost among its operating companies.

RESPONSE

The cost of the PJM integration cost/benefit study will be deferred in Account 186 as an RTO formation/integration cost and amortized in the future when it can be recovered from all users of the transmission system. The costs will be allocated and deferred on the seven AEP eastern operating companies' books based on transmission pole miles.

WITNESS: J Craig Baker

4

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 6 of the Baker testimony, lines 19-21. If AEP's application to join PJM were denied, will through and out rates be reinstituted? Explain the response in detail.

RESPONSE

The order eliminating through and out rates does not address the issue of whether such rates would be reinstated if AEP were not to participate in PJM.

WITNESS: J Craig Baker

5

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 8 of the Baker testimony, lines 10-13. Identify the costs for each year of the study period of the outsourced functions mentioned and whether or not they are discounted.

RESPONSE

Attached is a workpaper which identifies the costs for each study period of the outsourced functions including OASIS administration performed now by the Southwest Power Pool (SPP), reliability/security coordination performed now by PJM, and market monitoring performed now by Charles Rivers Associates. These costs are current contract costs and have not been discounted.

WITNESS: J Craig Baker

Calculation of Forecasted
Administration Charges
2004-2008

ANNUAL ADMINISTRATION OBLIGATION

CASE II - AEP SYSTEM OUTSIDE PJM
($ Thousands)

	2004		2005		2006		2007		2008	
Base Case	AEP-East	KPCo*	AEP-East	KPCo*	AEP-East	KPCo*	AEP-East	KPCo*	AEP-East	KPCo*
SPP(OASIS)	798.9	59.4	798.9	59.2	798.9	57.8	798.9	57.8	798.9	57.6
Charles Rivers	388.7	28.9	388.7	28.8	388.7	28.1	388.7	28.1	388.7	28.0
East Reliability Coordination	327.8	24.4	327.8	24.3	327.8	23.7	327.8	23.7	327.8	23.6
Total	1,515.4	112.7	1,515.4	112.3	1,515.4	109.6	1,515.4	109.6	1,515.4	109.2

Note: No inflation adjustment made through 2008.

*KPC allocation based on average Member Load Ratio (MLR) share of the AEP East system.

6

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to pages 8-9 of the Baker Testimony regarding the study performed to evaluate the costs and benefits of AEP's membership in PJM. Provide the input data and a detailed narrative description of the data AEP supplied to CERA for the study.

RESPONSE

The input data for load forecast, projected fuel data, and projected SO2 and NOX market prices are provided in Appendix A of the CERA report attached to Mr. Hoff Stauffer's testimony. The input data for the Smith Mountain pumped storage facility modeling information is attached.

WITNESS: J Craig Baker

Generator Name	Generating Capacity MW/Hr	Pumping MW/Hr	Reservoir storage weekly MWH	Efficiency %	Period
SMMTPS1	159	114	1941	71.43	week
SMMTPS2	155	82	1894	71.43	week
SMMTPS3	149	64	1821	71.43	week
SMMTPS4	122	31	1486	71.43	week
Energy Required to Pump reservoir full					

The default value = (GC * N)/CE

where:

GC = maximum generating capacity (MW)
N = number of generating hours per weekday
CE = cycle efficiency (per unit quantity)

7

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 8 of the Baker testimony, lines 8-11 and page 9 of the Baker testimony, lines 12-13.

What is the current status of through and out rates in light of FERC's November 17, 2003 order eliminating them?

RESPONSE

FERC's November 17, 2003 Order did not eliminate through and out transmission service rates, rather it eliminated the applicability of those rates to certain transactions, and required the filing of compliance rates, effective during a transition period, to recover revenues that will be lost as a result. The through and out rates of transmission providers affected by the Order will continue to be charged on transactions to points outside the defined region (systems that are not affected by the order), and to points within the region if the service was requested before November 17, 2003, regardless when service begins, and to transactions within the region if the service was requested on or after November 17, 2003, but service commences before April 1, 2004. Transactions to points within the region will be exempt from the through and out rates of the affected transmission providers if the service was requested on or after November 17, 2003 and service commences on or after April 1, 2004.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 8 of the Baker testimony, lines 8-11 and page 9 of the Baker testimony, lines 12-13.

Explain how the net benefits for each of the 5 years in the AEP/CERA study would change if the base case is changed to reflect the November 17, 2003 FERC order.

RESPONSE

AEP has not conducted a specific study of how the net benefits for each of the 5 years in the AEP/CERA study would change if the base case is changed to reflect the November 17, 2003 FERC Order. However, if the base case is changed to reflect the elimination of out and through rates under the November 17, 2003 FERC Order, study results would be expected to reflect net benefits for only (1) net FTR revenues and (2) avoided contract costs. Any remaining benefits would not be expected to be significant because AEP's low cost generation is nearly fully committed when available and dispatched to meet native load and off-system sales opportunities in today's non-RTO environment.

WITNESS: J Craig Baker

8

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 9 of the Baker testimony, lines 11-13. Does the AEP/CERA study reflect the impact of SECA rates?

a. If yes, identify the estimated impact, by year, for the study period and explain whether or not the amounts are discounted.

b. If no, explain why it is not necessary to reflect the impact of SECA rates, particularly since one scenario assumes the existence of through and out rates.

RESPONSE

a. & b. The SECA system makes it possible for AEP to incrementally increase wholesale power sales by reducing the transaction costs, so to that extent, the "impact of SECA rates" is reflected in the CERA study. From the cost impact standpoint, the "impact of SECA rates" is non-existent or negligible. This is so because the SECA rates are load-based charges that are assessed to replace transaction-based charges/revenues for transmission service. The implementation of SECA charges locks in transmission service charges associated with power imports and transmission revenues associated with power deliveries to/from the AEP System, and thus holds the related costs and revenues steady during the transition period. After the transition period, a new rate design that will fairly allocate the costs of the transmission system to all users will be implemented. AEP does not know what that new transmission rate design will be.

WITNESS: J Craig Baker

9

KPSC Case No. 2002-00475
Commission Supplemental Data Request
Order Dated January 22, 2004
Item No. 9

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 10 of the Baker testimony, lines 16 and 17. Explain how AEP proposes to allocate the cost of PJM participation between retail sales and off-system sales.

RESPONSE

The response assumes that "PJM participation" implies "PJM administrative costs". Those costs, inasmuch as they will be configured on an AEP-System basis, will be allocated on a member-load-ratio basis among the five operating companies of the AEP East Zone.

WITNESS: J Craig Baker

10

Definition and Purpose of Financial Transmission Rights (FTRs)

(1) Each FTR is defined from a point of receipt (where the power is injected onto the PJM grid) to a point of delivery (where the power is withdrawn from the PJM grid).

(2) FTRs can be designated to and from any single bus, Hub, Zone, Aggregate or Interface bus for which PJM calculates and posts LMP values.

(3) For each hour in which congestion exists on the Transmission System in the day-ahead market between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the Transmission Congestion Charges collected from the Market Participants.

(4) One purpose of FTRs is to protect Firm Transmission Service customers from increased cost due to Transmission Congestion in the day-ahead market when their energy deliveries are consistent with their firm reservations. FTRs are financial entitlements to rebates of congestion charges paid by the Firm Transmission Service customers.

(5) Financial Transmission Rights do not represent a right for physical delivery of power.

(6) Market Participants are able to acquire financial transmission rights in the form of options or obligations.

(7) The holder of the FTR is not required to deliver energy in order to receive a congestion credit.

(8) If a constraint exists on the Transmission System in the day-ahead market, the holders of FTRs receive a credit based on the FTR MW reservation and the LMP difference between point of delivery and point of receipt. This credit is paid to the holder regardless of who delivered energy or the amount delivered across the path designated in the FTR.

Valuation of Financial Transmission Rights (FTRs)

(9) The hourly economic value of an FTR is based on the FTR MW reservation and the difference between Day-ahead LMPs at the point of delivery and the point of receipt designated in the FTR.

FTR Obligations

(10) The hourly economic value of an FTR Obligation is based on the FTR MW reservation and the difference between Day-ahead LMPs at the point of delivery and the point of receipt designated in the FTR

(11) The hourly economic value of an FTR Obligation is positive (a benefit) when the path designated in the FTR is in the same direction as the congested flow. (The Day-ahead LMP at the point of delivery is higher than the Day ahead LMP at the point of receipt.)

(12) The hourly economic value of an FTR Obligation is negative (a liability) when the designated path is in the direction opposite to the congested flow. (The Day-ahead LMP at the point of receipt is higher than the Day ahead LMP at the point of delivery.); however, if the holder were to actually deliver energy along the designated path, they would receive a congestion credit that would offset the FTR charge.

FTR Options

(13) The hourly economic value of an FTR Option is based on the FTR MW reservation and the difference between Day-ahead LMPs at the point of delivery and the point of receipt designated in the FTR when that difference is positive.

(14) The hourly economic value of an FTR Option is positive (a benefit) when the path designated in the FTR is in the same direction as the congested flow. (The Day-ahead LMP at the point of delivery is higher than the Day ahead LMP at the point of receipt.)

(15) The hourly economic value of an FTR Option is zero (neither a benefit nor a liability) when the designated path is in the direction opposite to the congested flow. (The Day-ahead LMP at the point of receipt is higher than the Day ahead LMP at the point of delivery).

Acquiring Financial Transmission Rights (FTRs)

(16) You can acquire FTRs in three market mechanisms: Annual FTR Auction, Monthly FTR Auction or the FTR Secondary market

- ***Annual FTR Auction*** - PJM conducts an annual process of selling and buying FTRs through a multi-round auction. The Annual FTR auction offers for sale the entire transmission entitlement that is available on the PJM system on a long-term basis. The clearing mechanism of the Annual FTR Auction will maximize the bid-based value of FTRs awarded in the auction. Auction Revenue Rights (ARRs) are the mechanism by which the proceeds from the Annual FTR Auction are allocated.

- ***Monthly FTR Auction*** – PJM conducts a monthly process of selling and buying FTRs through an auction. The FTR auction offers for sale any residual transmission entitlement that is available after FTRs are awarded from the Annual FTR Auction. The auction also allows Market Participants an opportunity to sell FTRs that they are currently holding. Market Participants offer to sell or request to buy FTRs through PJM eFTR.

- ***FTR Secondary Market*** - The FTR secondary market is a bilateral trading system that facilitates trading of existing FTRs between PJM Members through PJM eFTR.

Annual FTR Auction

(17) PJM conducts an annual process of selling and buying FTRs through a multi-round auction.

(18) The Annual FTR auction offers for sale the entire transmission entitlement that is available on the PJM system on a long-term basis.

(19) The clearing mechanism of the Annual FTR Auction will maximize the bid-based value of FTRs awarded in the auction. FTRs are awarded in the Annual FTR auction for the following products:

- An on-peak FTR product valid for hours ending 0800 to 2300 weekdays, except NERC holidays.

- An off-peak FTR product valid for hours ending 2400 to 0700 on weekdays and for hours ending 0100 to 2400 on weekends and NERC holidays.

- A 24-hour product valid for hours ending 0100 to 2400 on all days.

- FTRs acquired in the annual auction have a term of one year.

(20) The Annual FTR auction is a multi-round auction consisting of four rounds. In each of the rounds 25% of the feasible FTR capability of the PJM system will be awarded. FTRs that are purchased in one round may be offered for sale in subsequent rounds. An auction participant must own any FTR that is offered for sale.

(21) Valid FTR sources and sinks in the Annual FTR auction are limited to hubs, zones, aggregates, generators, and interface buses.

(22) Only a subset of paths will be eligible for FTR Option bids in the Annual FTR Auction in order to prevent potential auction clearing performance issues.

(23) An ARR holder may self-schedule an FTR (up to the ARR MW amount) into the annual FTR auction as a "price-taker" auction buy bid. The self-scheduled FTR must have exactly the same source and sink points as the ARR and must be for a 24-hour product. The intent to self-schedule must be made prior to the closing of Round 1 to ensure feasibility of the requested FTR and to ensure that the amount paid for the FTR is exactly equal to the ARR Target Credit. 25% of the MW amount self-scheduled in Round 1 will clear in each round.

(24) PJM determines and posts the expected non-simultaneous estimates of available FTR capability for each interface, via the MUI.

(25) PJM initiates, directs, and oversees the following process for the Annual FTR auction.

- Annually, PJM conducts a multi-round auction that consists of four (4) rounds
- PJM opens the auction bidding period for each round and Market Participants may submit bids to purchase and offers to sell FTRs.
- The Bidding Period for each round of the Annual FTR auction will be open for three business days, closing at 1700 on the last day.
- PJM performs the FTR auction clearing analysis.
- Within two business days after the close of the Bidding Period for each round PJM posts FTR auction results on the MUI.

(26) The Annual FTR Auction must be conducted prior to the opening of the June Monthly Auction

(27) Market Participants must be a PJM Member or a PJM Transmission Customer to be eligible to submit bids or offers into the FTR auction.

(28) Invalid quotes into the auction are rejected. These quotes, may be resubmitted and if timestamped as received by PJM before the close of the auction bidding period, are included in the auction.

(29) The proceeds of the Annual FTR Auction are distributed to Auction Revenue Rights holders as described in the next sections.

Definition and Purpose of Auction Revenue Rights

(30) Auction Revenue Rights (ARRs) are the mechanism by which the proceeds from the Annual FTR Auction are allocated.

(31) At the beginning of each Annual Planning Period, ARRs are allocated to Network Transmission customers and to Firm Point to Point Transmission customers for the duration of the Annual Planning Period.

(32) Auction Revenue Rights are defined from a source Price Node to a sink Price Node for a specific MW amount.

(33) The economic value of each ARR is based on the MW amount and on the Locational Price differences between the source and sink node resulting from the Annual FTR Auction.

(34) Annual FTR Auction revenue is distributed to Auction Revenue Rights holders in proportion to, but not to exceed, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionally.

Stage 1 Allocation of Network Integration Service Auction Revenue Rights (ARRs)

(35) The Network Customer submits requests to Network Service ARRs via PJM eCapacity.

(36) All Network Service ARR requests must pass a Simultaneous Feasibility Test before being given PJM approval.

(37) PJM can approve all, part, or none of the ARR request based on the results of the Simultaneous Feasibility Test.

(38) The path for each Network Integration Service ARR is defined from specific historical generation resources to aggregate Network Customer Load in the Transmission Zone or other designated Load Aggregation Zone.

(39) The total ARRs requested from a historical generation resource to the LSE load cannot be greater than the MW amount of the resource that was assigned to the LSEs on a pro-rata basis.

(40) A participant's total ARR amount to a transmission zone cannot exceed the participant's total network peak load in that zone.

(41) ARRs are specified to the nearest 0.1 MW.

(42) PJM determines the set of eligible ARR sources for each transmission zone or for each historic load aggregation zone within a transmission zone based on the historical reference year that corresponds to the LMP-based market implementation for the transmission zone (Appendix 1 contains this information for each zone).

(43) Only long-term supply contracts or historical capacity contracts that were in place during the reference year and have a contract term of ten (10) years or greater (or were contracts with renewable options that were in place for ten (10) years or more prior to the reference year) are eligible to be considered historical generation resources for the purposes of Stage 1 allocation. This would include generation that was owned by an LSE and later sold but retained under a supply contract such that the generation was designated to the serve the load continuously for ten (10) years or greater.

(44) A historic load aggregation zone is defined as a sub-region of a transmission zone that was served under a separate set of supply contracts (i.e. by a municipal utility) than the other load in the transmission zone.

(45) PJM will assign to each LSE a pro-rata amount of the MW capability from each generator that is designated to the transmission zone or load aggregation zone based on the LSE's percentage of the total peak load in the transmission zone or in the load aggregation zone. LSE is notified of the generation resource assignments.

(46) Each LSE chooses the set of ARRs that it wants to request based on the generator sources it was assigned. The requested ARRs must source at the designated generator and must sink at the LSEs aggregate load in the transmission zone or in the load aggregation zone. The ARR request is limited to an amount not greater than the designated MW amount.

(47) PJM performs Simultaneous Feasibility test to determine the set of ARRs that can be awarded to each Network customer. PJM notifies each LSE of the ARR awards resulting from the Stage 1 allocation process and confirms with each LSE the ARRs awarded.

(48) A participant may surrender any portion of the ARR awards resulting form the Stage 1 allocation process prior to the commencement of the Stage 2 allocation process. provided that all remaining outstanding ARRs can be simultaneously accommodated following the return of such ARRs

Stage 2 Allocaton of Network Integration Service Auction Revenue Rights (ARRs)

(49) PJM will perform iterative allocation process that consists of four rounds.

(50) In every round of the four round allocation process, the Network Customer's ARR requests are limited to one fourth of the Network customer's peak load remaining unallocated after the stage 1 allocation process. For example, if the Network customer's peak load is 100 MW and they had received 60 MW of ARRs in Stage 1, then the ARR requests in each round of stage 2 are limited to (100-60)/4 = 10 MW.

(51) The source point of each ARR request may be any generator bus, Hub or external interface or load zone for which PJM calculates and posts an LMP value.

(52) The sink point of each ARR request must be the Network LSEs aggregate load in the transmission zone.

(53) In the first round, PJM staff performs the Simultaneous Feasibility test to determine the feasible set of ARRs that can be awarded. Proration is performed using same rule set as today. (This proration is performed in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.)

(54) At the end of Round 1 PJM notifies each Network Customer of the ARRs that they were awarded as a result of Round 1. After viewing the Round 1 results, Network customers submit ARR requests for Round 2. The allocation process continues in an iterative manner for four rounds.

(55) All Network Service ARR requests must pass a Simultaneous Feasibility Test before being given PJM approval.

(56) PJM can approve all, part, or none of the ARR request based on the results of the Simultaneous Feasibility Test.

(57) The path for each Network Integration Service ARR is defined from a generator bus, hub, zone or interface to aggregate Network Customer Load or other designated Load Aggregation Zone.

(58) A participant's total ARR amount to a transmission zone cannot exceed the participant's total network load in that zone.

(59) ARRs are specified to the nearest 0.1 MW.

Network Integration Service Financial Transmission Rights (FTRs) Allocation or New Load

(60) For a transitional period, Network Service Users and Firm Transmission Customers that take service that sinks in new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights.

(61) This transitional period covers the succeeding two annual FTR auctions after the integration of the new zone into the PJM interchange energy market.

(62) The election of a direct FTR Allocation shall be made prior to the commencement of each annual FTR auction.

(63) Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights may receive allocations of Auction Revenue Rights.

(64) Network Service Users and Firm Transmission Customers in new PJM zones must choose to receive either an FTR Allocation or an ARR Allocation. A customer cannot choose to receive both an FTR Allocation and an ARR Allocation.

(65) A transitional FTR Allocation will be conducted for new zone load being added as a result of market growth. This transitional allocation of FTRs will cover the period of time between the implementation of the new zone added as a result of market growth and the next Annual ARR Allocation process.

(66) All FTR requests in new zones made during these transition periods will be subject to the same allocation procedures as those set forth in the Annual ARR allocation process. These FTR requests must satisfy the same requirements as mentioned above for Annual ARR requests. The annual FTR allocation process for new zones will be conducted simultaneously with the Annual ARR allocation process for the other zones to ensure Simultaneous Feasibility of all rights.

(67) As part of the integration of new zones into the PJM Market, PJM will identify the set of eligible FTR sources for the stage 1 allocation process based on historic and contractual delivery patterns.

Allocation Process for Firm Point-to-Point Auction Revenue Rights (ARRs)

(68) To qualify to participate in the Annual ARR Allocation process, firm point-to-point ARR requests must be associated with firm point-to-point service that spans the entire next planning period and is confirmed by the opening of the Annual ARR Nomination period. Such firm transmission service customers may submit ARR requests during the stage 2 allocation process.

(69) The Stage 2 allocation analysis for Network Service And Firm point-to-point service ARRs is performed together as a single Simultaneous Feasibility analysis.

(70) The Firm Transmission customer may enter an ARR request into Round 1 for up to one fourth of the Firm Point-to-Point transmission service MW amount. The ARR source must be the source point that is designated in the transmission service request and the ARR sink must be the sink point that is designated in the transmission service request.

(71) At the end of Round 1 PJM notifies each Firm Point-to-Point transmission customer of the ARRs that they were awarded as a result of Round 1.After viewing the Round 1 results, the Firm Point-to-point transmission customers submit ARR requests for Round 2. The iterative allocation process continues for four rounds.

(72) All Firm Point-to-Point Transmission Service ARR requests must pass a Simultaneous Feasibility Test before being given PJM approval.

(73) PJM can approve all, part, or none of the ARR request based on the results of the Simultaneous Feasibility Test.

(74) The following procedure is used in processing Firm Point-to-Point ARRs outside of the Annual ARR Allocation window:

- The Firm Point-to-Point Transmission Customer submits Transmission Service Requests (TSRs) via OASIS, including the optional request for the associated ARR.
- PJM conducts a Simultaneous Feasibility Study of the ARR request and notifies the Transmission Customer of TSR and ARR status via OASIS.
- Firm Point-to-Point Transmission Customers notify PJM of acceptance or rejection of TSRs and their associated ARRs via OASIS.

(75) The timeline for the TSR/ARR request and approval process for Firm Point-to-Point Transmission Service are shown in the following table:

	Annual	Monthly	Weekly	Daily
Earliest Request, before start of service	No Limit	18 months	2 weeks	3 days
Latest Request, before start of service	2 months	14 days	7 days	2 days
OI Respond, after receipt of TSR	1 month	Per Tariff	2 days	4 hours
Customer Confirm, after OI Response	15 days after PJM approves OR By 12:00 noon on day prior to service commencement			
Maximum Term	No Limit	1 month	2 weeks	2 days

(76) All Point-to-Point ARRs requests must pass a Simultaneous Feasibility Test before being given PJM approval.

(77) PJM can approve all, part, or none of the ARR request based on the results of the Simultaneous Feasibility Test.

(78) The path for each Point-to-Point ARR is defined from the source to the sink, as specified in the TSR.

(79) The MW value of each Firm Point-to-Point ARR may be up to the megawatts of the Firm Transmission Service being provided.

(80) Firm Point-to-Point Transmission Service Customers must enter the amount of ARRs they desire in the "ARRs Requested" field on the OASIS Buy page. This value is considered an "up to" amount. Therefore, a Transmission Customer should enter the maximum amount of the ARRs that they desire, not to exceed the capacity value of the transaction.

(81) A Transmission Customer requesting Firm Point-to-Point Transmission Service that does not want ARRs should enter a "0" in the "ARRs Requested" field on the OASIS Buy page.

(82) Prior to placing the transaction in the Accepted status, PJM enters the amount of ARRs awarded in the "ARRs Award" field in OASIS.

(83) For Firm Point-to-Point Transmission Service out of or through the PJM Control Area, the Source is either the generation resource within the PJM Control Area or the interconnection with the sending Control Area; and the sink of delivery is the point of interconnection with the receiving Control Area.

(84) The duration of each Firm Point-to-Point ARR is the same as the associated Firm Transmission Service, which may be one year (starting at the beginning of any month), one month (starting the first day of the month), one week (Monday through Sunday), or one day (hours 1 through 24).

(85) If an approved ARR spans multiple planning periods, the ARR is technically only approved until the end of the first Planning Period. Prior to each new Planning Period, PJM re-evaluates all ARRs for feasibility. If ARR reductions are required due to infeasibility, then the ARRs are reduced in proportion to their MW value and level of impact on the binding constraint in the Simultaneous Feasibility Test

(86) An ARR associated with long term (1 year or more) Firm Point-to-Point Transmission Service will be allocated on a first come first served basis if the request falls outside the Annual open enrollment window. If the request can be considered within the annual open enrollment window, then the request will be process on the same priority as Network Service-based requests.

Reassignment of ARRs for Shifts in Load Responsibility

(87) Within the planning period, as load changes from one LSE to another within a transmission zone, a proportionate share of the ARRs defined to sink into the zone are reassigned from the old LSE to the new LSE as described in the "Reassignment of ARRs for Shifts in Load Responsibility" section .

(88) ARRs allocated for the planning period will be reassigned on a proportional basis within a zone as load switches between LSEs within the planning period.

(89) The reassignment of ARRs is an automatic process which is conducted on a daily basis.

(90) ARRs are only reassigned from those LSEs that have lost load in a zone and have a net positive economic ARR position to that zone.

(91) An LSE that loses load will lose the economic value of its ARRs in proportion to the amount of load lost.

(92) The economic value of the total set of ARRs lost by LSEs losing load in a zone will be reallocated to LSEs gaining load in the zone in proportion to each LSE's MW load gain relative to the total load shifted in the zone

Allocation of Incremental Auction Revenue Rights (ARRs) associated with Transmission Expansion

(93) Transmission expansion projects associated with new generation interconnection and Merchant Transmission Expansion projects will be allocated incremental ARRs in a three-round allocation process in which the customer requests incremental ARRs for three pairs of point-to-point combinations (one point-to-point combination is requested per round).

(94) In each round, one-third of the Incremental ARRs made available by the expansion project will be assigned to the requester.

(95) After each of rounds one and two, the requester may accept the assigned Incremental ARRs or refuse them. Acceptance of the assignment will remove the assigned Incremental ARRs from availability in the next rounds. Refusal of the assignment will result in the Incremental ARR being available for the next round.

(96) The Incremental ARR assignment made in round three will be final and binding.

(97) Incremental ARRs will be effective for thirty years or the life of the facility or upgrade, whichever is less.

(98) At any time during this thirty-year period, in lieu of continuing this thirty-year ARR, the Interconnection Customer shall have a one-time choice to switch to an optional mechanism, whereby, on an annual basis, the customer has the choice to request an ARR during the Annual ARR allocation process between the same source and sink, subject to simultaneous feasibility. Once this option is chosen, the Interconnection Customer must request the Incremental ARR during each annual ARR enrollment period for the upcoming planning period. If no request is made, the Incremental ARR is forfeited for that planning period.

(99) At any time during this thirty-year period, an Interconnection Customer may return Incremental ARRs that is no longer desires, provided that all remaining outstanding ARRs can be simultaneously accommodated following the return of such ARRs. If the Interconnection Customer returns Incremental ARRs, the Interconnection Customer shall have no further rights regarding such Incremental ARRs.

Distribution of FTR Auction Revenues

(100)Annual and Monthly FTR auction revenues are distributed to Auction Revenue Rights holders in proportion to (but not to exceed) the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(101)Excess revenues after distribution to ARR holders will be used to fund any shortfall in FTR Target Allocations over the calendar year.

(102)These funds are accounted for on a monthly basis as Excess Congestion Charges and they are distributed with other Excess Congestion Charges as described in the section entitled "FTR Settlements - Distributing Transmission Excess Congestion Charges".

Auction Revenue Rights (ARR) Settlement

(103)The settlements for Auction Revenue Rights will be based on the clearing prices from each round of the annual FTR auction.

(104)The amount of the credit that the ARR holder should receive for each round is equal to the MW amount of the ARR (divided by the number of rounds) times the price difference from the ARR delivery point to the ARR source point as shown in the following formula:

(105) $ARR\ Target\ Allocation = (ARR/\#\ of\ rounds) * \left(LMP_{Delivery} - LMP_{Source} \right)$

(106)Note: The LMP values in the above equation are results from the appropriate round of the annual FTR auction

(107)The ARR Target Allocation can be positive or negative which means that an ARR can be either a benefit or liability to the holder depending on the direction of transmission congestion in the annual auction analysis.

(108)If sufficient funds are collected in the Annual and Monthly FTR Auction to satisfy all ARR Target Allocations then the ARR Credits = ARR Target Allocations for all ARR holders.

(109)The ARR Credits may be prorated proportionately if there are insufficient annual and monthly FTR auction revenues collected to cover all of the ARR credits.

(110)If the ARR Credits are prorated, the difference between ARR Target Allocations and ARR Credits are called ARR deficiencies. The ARR deficiencies may be funded by Annual Excess Congestion Charges as explained in the "FTR Settlements" Section.

(111) The settlements for the Annual FTR Auction and the corresponding ARR settlements will be performed on a monthly daily basis.

Financial Transmission Rights (FTR) Settlements

Calculating Transmission Congestion Target Allocations

(112)The Transmission Congestion Credit Target Allocation is the amount of credit the FTR holder should receive in each constrained hour due to the value of an FTR.

(113)The PJM OI determines a target allocation of Transmission Congestion Credits for each hour for each FTR by using the following formula:

$$Target\ Allocation = FTR * \left(DALMP_{Delivery} - DALMP_{Receipt} \right)$$

where:

- *FTR* - Financial Transmission Rights between the designated load bus and the designated generation bus, in megawatts
- $DALMP_{Delivery}$ - The Day-ahead LMP during the hour at the Point of Delivery designated in the FTR
- $DALMP_{Receipt}$ - The Day-ahead LMP during the hour at the Point of Receipt designated in the FTR

(114)The total target allocation for a Market Participant for each hour is then the sum of the target allocations for all of the Market Participant's FTRs.

Note, if the $DALMP_{Delivery}$ or the $DALMP_{Receipt}$ is an aggregate zone, the following formula is used:

$$Target = FTR * \sum Load\ Percentage_i * \left(DALMP_{Delivery-i} - DALMP_{Receipt} \right)$$

where:

- *FTR* - Financial Transmission Rights between the designated Load Aggregation Zone and the designated bus, in megawatts
- *Load Percentage$_i$* - The percentage of the load at time of annual peak associated with each individual load bus in the Load Aggregation Zone designated in the FTR

Calculating Transmission Congestion Credits

(115)The PJM OI compares the total of all Transmission Congestion Credit target allocations to the total Transmission Congestion Charges for the PJM Control Area in each hour resulting from the Day-Ahead Market and from the Real-time Market.

(116)If the total of the target allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each FTR is equal to its target allocation. All excess Transmission Congestion Charges are distributed at the end of the month as described later in the "FTR Settlements" section.

(117)If the total of the target allocations is equal to the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each FTR is equal to its target allocation.

(118)If the total of the target allocations is greater than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each FTR is equal to a share of the total Transmission Congestion Charges in proportion to its target allocation. The shortfalls in hourly Transmission Congestion Charges may be offset by excess charges from other hours in the end of the month accounting, as described in the next section.

Distributing Excess Transmission Congestion Charges

The objective of the monthly excess Transmission Congestion Charge distribution is to cover any deficiency in the share of Transmission Congestion Credits received by each FTR holder during the month as compared to their target allocations for the month.

- *Stage One* - The PJM OI distributes excess Transmission Congestion Charges accumulated during the month to each holder of FTRs in proportion to, but not greater than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total target allocations for the month.
- *Stage Two* - Any remaining excess after the stage one distribution will be used to satisfy any FTR deficiency from previous months within the calendar year on a pro-rata basis up to the full FTR Target Allocation value.
- Stage Three – Any remaining excess after the stage Two distribution will be carried forward to the next month as excess congestion charges.
- Stage Four - At the end of the calendar year, any remaining Excess Congestion Charges will first be used to satisfy any ARR deficiency that may

exist. If insufficient funds exist to honor all ARR revenue shortfalls then the funds would be distributed by ratio of the ARR deficiency.

- *Stage Five* - The PJM OI distributes any excess Transmission Congestion Charges remaining after the stage Four distribution to Network Customers and Firm Point-to-Point Transmission Customers in proportion to their Demand Charges for Network Integration Service and their charges for Reserved Capacity for Firm Point-to-Point Transmission Service, regardless of whether these customers hold FTRs for their Transmission Service.

Simultaneous Feasibility Test

(119)The Simultaneous Feasibility Test (SFT) is a market feasibility test run by PJM that provides revenue adequacy by ensuring that the Transmission System can support the subscribed set of FTRs or ARRs during normal system conditions. If the FTRs or ARRs can be supported under normal system conditions and congestion occurs, PJM will be collecting enough congestion charges to cover the credits, thus becoming revenue adequate.

(120)The purpose of the SFT is to preserve the economic value of FTRs or ARRs to the holders by ensuring that all FTRs or ARRs awarded can be honored. An SFT is run for each FTR requested.

(121)The SFT uses a DC power flow model that models the requested firm transmission reservations and expected network topology during the period being analyzed. It is not a system reliability test and is not intended to model actual system operating conditions.

(122)FTRs and ARRs for Firm Point-to-Point Service are modeled as generation at the receipt (source) point(s) and load at the delivery (sink) point(s).

(123)FTRs and ARRs for Network Integration Service are modeled as a set of generators at the receipt (source) point and a network load at the delivery (sink) point.

(124)SFTs are run for yearly, monthly, and weekly analysis periods, when network resource changes are submitted, and during the determination of the winning quotes for the Annual FTR Auction and the Monthly FTR auction.

(125)Inputs to the SFT model include:

- all newly-requested FTRs or ARRs for the study period,
- all existing FTRs or ARRs for the study period,
- transmission line outage schedules,

- thermal operating limits for transmission lines,
- PJM reactive interface limits that are valid for the study period, and
- estimates of uncompensated power flow circulation through the PJM Control Area from other Control Areas.

(126)Consistent with PJM Operating and Planning criteria, the SFT evaluates the ability of all system facilities to remain within normal ratings during normal, extended-period operation, while maintaining an acceptable bulk system voltage profile.

(127)The system must also be able to sustain any single contingency event with all system facilities remaining within applicable short-term, emergency ratings while maintaining an acceptable bulk system voltage profile and a maximum bulk system voltage drop of five percent.

(128)To ensure feasibility, each constraint is monitored for limit violation by the worse-case combination of awarded FTR options and obligations. Counterflow created by an FTR option is ignored.

Monthly FTR Auction

(129)The Monthly FTR auction provides a method of auctioning the residual FTR capability that remains on the PJM Transmission System after the Annual FTR Auction is conducted.

(130)The auction also allows Market Participants an opportunity to offer for sale any FTRs that they currently hold. An auction participant must own any FTR that is offered for sale.

(131)PJM conducts the auction once a month.

(132)FTRs acquired in an auction entitle the holder to credits for transmission congestion charges for one calendar month FTRs are awarded for the following products:

- FTRs can be either options or obligations.
- An on-peak FTR product valid for hours ending 0800 to 2300 on weekdays.
- An off-peak FTR product valid for hours ending 2400 to 0700 on weekdays and for hours ending 0100 to 2400 on weekends and NERC holidays.
- A 24-hour product valid for hours ending 0100 to 2400 on all days.

(133)FTRs acquired in a monthly FTR auction have the following characteristics

- a term of one month
- are available between any single bus or combination of buses for which an LMP is calculated and posted (subject to simultaneous feasibility). The list of buses includes hubs, zones, aggregates, and single buses. Only a subset of paths will be eligible for FTR Option bids in order to prevent potential auction clearing performance issues.
- may be designated from injection buses outside PJM and withdrawal locations outside PJM or buses with injections and withdrawals within PJM
- can be reconfigured, meaning that the FTR auction not only allows Market Participants to purchase the FTRs offered into the auction by sellers, but also enables buyers to purchase FTRs that are different from any of the FTRs offered into the auction by sellers
- hedge the FTR holder against congestion payments to PJM when energy delivery is consistent with the FTR's definition
- do not hedge the FTR owner against payment for losses
- are treated in same manner as FTRs acquired in the Annual Auction for purpose of calculating target allocation of Transmission Congestion Credits and allocation of Transmission Congestion Credits
- The FTR Auction will calculate the auction value for all FTR options and obligations, regardless of whether they are bought or sold in the auction.
- To ensure feasibility, each constraint is monitored for limit violation by the worse case combination of awarded FTR options. Counterflow created by an FTR option is ignored.
- The clearing price of an FTR Option Buy Bid will never be less than zero.
- The clearing price of an FTR option will always be greater than or equal to the clearing price of an FTR Obligation for the same path..
- The clearing price of an FTR Option is a function of the shadow price of each binding constraint and cannot be computed directly from the nodal prices.
- The clearing price of any FTR Obligation can be computed directly from the nodal prices.

- The clearing price of an A-to-B FTR Obligation is equal to the negative of the clear price of a B-to-A FTR Obligation -- this is not true for the FTR Options since the clearing prices of FTR Options are never negative.

(134)The winning quotes are determined by the set of simultaneously feasible FTRs with the highest total auction value, as determined by the bids of the buyers and taking into account the reservation prices of the sellers.

- The valuation of the awarded FTRs during the auction is based on the quotes submitted into the FTR Auction. Therefore, the set of quotes that maximizes the quote-based value of the awarded FTRs to the Market Participants that would receive them is the winning set.

- This ensures that PJM awards the set of FTRs and allocates them among auction participants in such a way that the value-based transmission utilization is maximized.

(135)The major steps performed to determine the winning quotes include:

(1) Downloading data for the FTR market user database.
(2) Solving the linear program problem.
(3) Checking the simultaneous feasibility of the FTR auction solution.
(4) Repeating Steps 2 and 3.
(5) Uploading the results to the FTR MUI.

(136)After determining the winning quotes, settlements occur. Winning bidders pay market price for FTRs acquired in the auction; FTR sellers are paid market price for the FTRs they surrender to PJM. This settlement is separate from the transmission congestion settlements.

(137)All monthly auction revenues are first allocated among ARR holders in proportion to the holder 's deficiencies from the Annual FTR Auction. Any revenues remaining after this allocation are treated as excess congestion congestion charges and are distributed starting with Stage Two as described in the "Distributing Excess Transmission Congestion Charges" section.

PJM initiates, directs, and oversees the Monthly FTR auction. The following timeline defines open, close and clearing dates for all monthly auctions.

- Thirteen business days prior to the start of the auction month, PJM opens the auction bidding period and Market Participants may submit bids to purchase and offers to sell FTRs. PJM determines and posts the expected non-simultaneous estimates of available FTR capability for each interface, via the MUI.

- Ten business days prior to the start of the auction month, the auction closes at 1700 of the last day.
- PJM performs the FTR auction clearing analysis.
- Within two business days of the bidding period closing, PJM posts FTR auction results on the MUI.

(138) Market Participants must be a PJM Member or a PJM Transmission Customer to be eligible to submit bids or offers into the FTR auction.

(139) Market Participants cannot submit offers to sell FTRs that they do not own at the time of the bid submittal.

(140) Invalid quotes into the auction are rejected. These quotes may be resubmitted and if timestamped as received by PJM before the close of the bidding period are included in the auction.

Annual FTR Auction Credit Business Rules

(141) Market Participants must have established an Auction Credit Limit prior to bidding in any FTR Auction.Auction Credit Limits may be established by utilizing the unused portion, if any, of a Market Participant's currently established Unsecured Credit Limit at PJM, or may be established by providing additional Financial Security, of a type that is acceptable under PJM's Credit Policy. Credit requests should be made to PJM's Treasury Department at least two weeks prior to opening of the first round of bidding. Previously established credit with PJM will not be available for the FTR Auction unless the Market Participant specifically makes such a request to the PJM Treasury Department and confirms it with the FTR Markets group.

(142) The Credit Requirement for a Market Participant's bids may not exceed its Auction Credit Limit. Positive bids for which the bidder holds matching ARR's will not be counted in the bid total. If, during any auction round, the total Credit Requirement for a Market Participant's previously accepted and currently submitted aggregate bids exceeds the Market Participant's Auction Credit Limit, all currently submitted bids will be rejected. PJM will attempt to work with bidders to increase credit during the auction process, if desired, but cannot guaranty doing so in a particular timeframe. It is highly unlikely that any increase in credit can be accomplished in the final day of a bidding round.

(143) Market Participants with successful bids must maintain credit (the Credit Requirement) for those successful bids after the auction. After the auction, PJM will release, if applicable, and if requested by the Market Participant, any credit

provided for the auction that is not needed to satisfy the remaining Credit Requirement for the Market Participant's winning bids.

(144)A Total Credit Requirement will be calculated for every Market Participant. The Credit Requirement will be calculated as the sum of the individual credit exposures for all FTR's the Market Participant is currently bidding for, or has already won. Calculations for individual FTR's that result in a value of zero or less will be set to zero.

The Credit Requirement for individual FTRs that are self-scheduled using an ARR will be calculated as:
Price of the bid for that FTR
Less: Value of ARR credits for that FTR
Less: Revenue Offset for that FTR

The Credit Requirement for individual FTRs that are not self-scheduled using an ARR will be calculated as:
Price of the bid for that FTR
Less: Revenue Offset for that FTR

The sum of the Credit Requirement Credit Requirement for all of a Market Participant's non-self-scheduled FTRs will be offset by the total value of the Market Participant's ARRs that were not used to self-schedule an FTR in the auction.

The Revenue Offset will be calculated as the difference between the expected LMP values at the source and sink adjusted to account for the volatility at the nodes.

(145)Credit Requirements may be reviewed and changed as needed. Credit exposure for all participants may be reviewed as needed by PJM to determine if the Credit Requirement for the Market Participant has increased. If the Credit Requirement exceeds credit currently in place, the party must increase its credit for its FTR obligations. PJM will review the FTR annual auction market after six months of operation to determine if any reduction in credit requirement is warranted at that time.

(146)Credit provided for the FTR auction must be non-cancelable for the entire auction period. Any credit enhancement provided for FTR purposes that has a termination date (e.g. corporate guaranty or letter of credit) must be non-cancelable until at least 10 days after payment is due for the last month of the auction.

(147)Credit responsibility for an FTR that is traded within PJM's eFTR system remains with the original party unless/until the receiving party ("3rd party") establishes sufficient acceptable credit with PJM.

If a Market Participant owns an FTR and later trades that FTR to a 3rd party (using eFTR), then

(a) PJM will include the traded FTR payments and revenue credits on the 3rd party's bill each month, but the original party retains the obligation to pay for the FTR (offset by associated revenue credits) if the 3rd party defaults on its payment obligation to PJM prior to credit responsibility being transferred to the 3rd party.

(b) Once the 3rd party establishes sufficient credit acceptable to PJM for its new FTR obligation, then PJM will notify both parties that the 3rd party has assumed credit responsibility for the FTR, and the original party is released from its credit responsibility for the FTR. PJM cannot guaranty that a 3rd party will establish sufficient credit acceptable to PJM. Market Participants trading FTR's to 3rd parties may retain credit responsibility for those FTR's up to the duration of the annual auction period. Parties may work with PJM to establish credit prior to a trade.

(c) If a 3rd party defaults, and has not yet assumed credit responsibility for one or more of its FTR's, then the original party will be responsible to pay a portion of the default, prorated based its FTR's contribution to the defaulted invoice.

(d) FTR's may be traded multiple times, but the original party retains credit responsibility until it is assumed by a 3rd party.

(e) FTR's that are traded for less then the remaining duration of the annual auction period will remain the credit responsibility of the original party.

FTR Secondary Markets

(148)The PJM FTR secondary trading market is a bilateral trading system that facilitates the trading of existing FTRs between PJM Members, using a bulletin board system in PJM eFTR.

(149) The FTR secondary market allows trading of existing FTRs only.
- For FTR trades made through eFTR, PJM automatically transfers ownership and adjusts the PJM Members' monthly billing statements accordingly.

- You can also trade FTRs independently of eFTR. However, PJM has no knowledge of such trades and, therefore, is not able to adjust PJM Members' monthly billing statements appropriately.

(150)To buy and sell FTRs through eFTR, you must be a PJM Member or a PJM Transmission Customer. To register, use the eFTR User Registration Page, which is available on the PJM Web Site.

(151)When an FTR is traded, the associated firm transmission capacity is not reassigned, just the financial entitlements.

(152)If a Market Participant owns an FTR and later trades that FTR to a 3rd party (using eFTR), then PJM will include the traded FTR payments and revenue credits on the 3rd party's bill each month, but the original party retains the obligation to pay for the FTR (offset by associated revenue credits) if the 3rd party defaults on its payment obligation to PJM prior to credit responsibility being transferred to the 3rd party.

(153)Credit responsibility for an FTR that is traded within PJM's eFTR system remains with the original party unless/until the receiving party ("3rd party") establishes sufficient acceptable credit with PJM.

(154) An FTR which is awarded in the annual auction cannot be traded through eFTR until after the completion of Round 4.

(155)On the secondary market, an FTR can be split into multiple FTRs with different MW amounts and different start and end times than the original FTR. However, an FTR cannot be reconfigured into FTRs with a larger total MW value, earlier start time, later end time, or different path.

(156)On the FTR secondary market, an FTR Obligation can only be traded as an FTR Obligation and an FTR Option can only be traded as an FTR Option. An FTR Obligation cannot be reconfigured as an FTR Option and an FTR Option cannot be reconfigured as an FTR Obligation.

(157)FTR MW values can be split in 0.1 MW increments.

(158)All FTR trades for a given day are locked out at midnight of the current day.

(159)Once per day, eFTR database sends updated FTR information reflecting the previous day's trades to the PJM Market Settlements system for use in preparing reports and monthly billing statements.

11

Kentucky Power
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American Electric Power

REQUEST

Refer to page 13 of the Baker testimony, line 21.

Does PJM allow utilities whose generation adequacy is under state commission review to opt-out of Schedule 9-5, Capacity Resource and Obligation Management?

RESPONSE

No.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 13 of the Baker Testimony, line 21.

If no, to what extent does AEP believe that the lack of an opt-out provision is related to PJM's history as a tight power pool; that is, is there a possibility that PJM might consider allowing new, non-pool members to opt-out of Schedule 9-5?

RESPONSE

Schedule 9-5 concerns the administrative costs of participation in the various activities described in Schedule 9-5 (a). Since new members, even though they were not members of the classic PJM power pool, will be participating in these activities, AEP does not believe that PJM would consider allowing such new members to opt-out of this schedule.

WITNESS: J Craig Baker

Kentucky Power
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American Electric Power

REQUEST

Refer to page 13 of the Baker testimony, line 21.

Does PJM's Capacity Resource and Obligation Management schedule supersede state authority to determine reasonable resource requirements? Explain the response.

RESPONSE

PJM's Capacity Resource and Obligation Management Service, Schedule 9-5, concerns the administrative costs of participation in the various activities described in Schedule 9-5 (a) and not resource requirements.

WITNESS: J Craig Baker

12

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 14 of the Baker Testimony regarding PJM's administrative fees. Describe the nature of the adjustments that were made to PJM's individual 2005 rates based on its bundled rate estimates through 2008.

RESPONSE

PJM provided their forecast of bundled rate estimates for the study period. The bundled rate estimates were used to adjust (either up or down) the projected 2005 individual PJM Schedule 9-1 through 9-5 administration rates that PJM also provided, reflecting the integration of the four new transmission zones (AEP, CE, DPL and VP).

WITNESS: J Craig Baker

13

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American Electric Power

REQUEST

Refer to page 15 of the Baker testimony, lines 12 and 13, and page 17, lines 4-7. Are the situations described therein that result in no difference to AEP's cost of capacity or capacity obligations likely to continue? Explain the response in detail.

RESPONSE

Yes. As noted in Mr. Baker's testimony at Page 16, line 16 through Page 17, line 2, the long-term cost of capacity for a member or non-member of PJM should be about equal.

WITNESS: J Craig Baker

14

Kentucky Power
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American Electric Power

REQUEST

Refer to pages 15-16 of the Baker Testimony regarding required reserve margins.

a. Provide a narrative description, along with supporting workpapers, calculations, etc., that reflect how AEP will receive credit for the diversity between its own peak and load at the time of the PJM peak and how the diversity was quantified.

b. Provide a narrative description, along with supporting workpapers, calculations, etc., that demonstrate the differences between recent AEP forced outage rates and longer-term forced outage statistics for PJM as a whole, which PJM's reserve margin calculations take into account.

RESPONSE

a. Page 2 of this response contains the workpaper which provides the results of PJM's Installed Reserve Margin and load diversity analysis.

b. Page 3 of this response contains the workpaper which provides the calculation of AEP's resultant reserve requirement of 12.0025%. Confidential protection of this workpaper is being requested in the form of a Motion for Confidential Treatment.

WITNESS: J Craig Baker

01/09/03 05:25 PM

Subject: Installed Reserve Margin

At its meeting yesterday, the PJM Board Reliability Committee endorsed a 15% installed reserve margin for the expanded PJM RTO for the June 1, 2003 - May 31, 2004 planning period. With a PJM average forced outage rate of 6.55%, the 15% installed reserve margin converts to a Forecast Pool Requirement (or unforced reserve margin) of 1.0747.

We've completed the load diversity analysis and the results indicate that the yearly diversities for each zone vary greatly from year to year. The PJM average diversity, however, is fairly stable over the eight year period we studied. Due to the extreme volatility of the company specific diversity factors, we will apply the PJM average diversity of 2.5% to all PJM zones for the upcoming summer. After we gain more experience with the new zones, we may modify this diversity adjustment for future planning periods.

We will schedule a conference call shortly to discuss these results and define next steps.

Steven R. Herling
Executive Director, System Planning
PJM Interconnection, L.L.C.

CONFIDENTIAL

15

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REQUEST

Refer to page 18 of the Baker testimony, lines 7-10. Describe any sensitivity analysis, margin of error estimates, uncertainty analysis or the equivalent that were performed to test the reasonableness of the results reflected here.

RESPONSE

Please refer to the last page of the CERA report for an explanation of margin of error estimates and effect of uncertainties on the study results.

WITNESS: J Craig Baker

16

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REQUEST

Refer to Exhibit JCB-1 to the Baker Testimony, which shows $4 million as the average annual PJM administrative charges to be assigned to Kentucky Power for the 2004-2008 period. In the initial phase of this case, Kentucky Power estimated that its share of PJM administrative charges for AEP would be approximately $3 million annually.

a. Explain why the estimate has increased by $1 million since that time.

b. Explain in detail the amount of costs incurred to date by AEP to integrate its system into PJM, and the total estimated costs to achieve integration. How will those costs be recovered and what will Kentucky Power's share be?

RESPONSE

a. Earlier in 2003, PJM had provided an annual projected operating expense budget estimate for 2004-2008 of approximately $300 million. Revised forecasts from PJM show the 2005 operating expense budget to be $334 million rising to $362 million in 2007.

b. The amount of costs incurred by AEP as of December 31, 2003, excluding carrying charges, for integration into PJM are $13.8 million which are being deferred in Account 186. The deferred costs at December 31, 2003, consists of AEP's share of PJM's start-up expenses billed by PJM of $11.5 million and other AEP deferred incremental costs to achieve integration of $2.3 million. AEP is working with PJM on updates to estimates of total costs to achieve integration. On July 2, 2003, the FERC issued an Order reinforcing prior Orders and granting AEP's request to defer RTO start-up and PJM integration costs and related carrying charges until AEP integrates with PJM. The Order also provides that AEP will have to make a separate filing to request recovery of these deferred costs, demonstrating that the costs were prudently incurred, to seek approval to establish a regulatory asset and to seek approval of an amortization plan for the regulatory asset. AEP intends to seek permission to amortize the deferred PJM integration costs as those costs are recovered from all users of AEP's transmission system, including the customers of KPCo, through a PJM administrative fee billed by PJM to transmission customers in the AEP zone (including AEP as a customer on behalf of its retail loads). KPCo's estimated share of costs will be in the range of six to seven percent of the total deferred PJM integration costs.

WITNESS: J Craig Baker

17

Kentucky Power
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REQUEST

Refer to page 21 of the Baker testimony, lines 14-22.

a. Is PJM currently functioning as reliability coordinator for AEP?

b. Specifically, how will reliability be enhanced to Kentucky Power customers as a result of AEP's membership in PJM?

RESPONSE

a. Yes, PJM is currently functioning as Reliability Coordinator for AEP.

b. Transmission reliability is achieved through a continuum of long-term planning, short-term operational planning, and real-time operations. As a member of PJM, each of these functions, currently performed by AEP, will be augmented by coordination with PJM.

As part of long-term planning, transmission expansion plans will be coordinated and developed for the entire PJM footprint via a single process, assuring a consistent view of needs and expansion timing, while minimizing expenditures.

In short-term operational planning, operating procedures will be identified and studied on the larger footprint, thereby enabling the development of effective operating procedures that will include all actions within PJM that could correct and control limitations. Generation and transmission outage scheduling will be coordinated to ensure conflicting outages do not diminish reliability, and to maintain transmission capacity to the extent possible.

During real-time operations, as a member of PJM and part of the PJM market, transmission constraints will be mitigated via LMP, using only transmission loading relief ("TLR") as a back-up/back stop constraint mitigation procedure. Emergency conditions will be addressed through a coordinated response among numerous entities working together under a single structure.

Also, please refer to Mr. Baker's Direct Testimony on Rehearing, Page 23, lines 16-23 and Page 24, lines 1-5.

WITNESS: J Craig Baker

Kentucky Power
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American Electric Power

REQUEST

Refer to page 22 of the Baker Testimony regarding the merger savings passed through to Kentucky Power's ratepayers since July 2000 as a result of AEP's merger. Mr. Baker states, clearly, if AEP had not agreed to join a Regional Transmission Organization ("RTO"), the FERC would not have approved the merger and therefore, the Kentucky ratepayers would not have received the "credits". It is understood that in the merger proceedings FERC has imposed conditions requiring utilities to join RTOs in order to mitigate the utilities potential market power. However, other means of mitigating market power have been considered in various FERC proceedings in recent years.

a. Given that there are other means by which market power may be mitigated, is AEP able to state unequivocally that its merger would not have been approved absent its agreement to join an RTO?

b. If the response to part (a) of this request is affirmative, provide any evidence that supports that response.

RESPONSE

At the time of the merger proceeding, FERC regarded RTO participation as necessary to mitigate transmission, or "vertical", market power, which it defined as the ability of the merged entity to use transmission to frustrate competitors' access to competitive markets. AEP is not aware of any change in this FERC policy. Mr. Baker stands by his testimony that if AEP had not agreed to join an RTO, the FERC would not have approved the merger.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 23 of the Baker testimony, lines 9-12.

a. Describe the history of AEP's attempts to gain approval of the Wyoming-Jackson's Ferry 765-kV line and the current status.

b. How would AEP being a member of PJM impact the construction of the Wyoming-Jackson's Ferry 765-kV line?

RESPONSE

a. As originally proposed in 1991, the project consisted of a 115-mile transmission line connecting AEP's Wyoming Station, near Oceana, West Virginia, to its Cloverdale Station, near Roanoke, Virginia. In developing the route for the proposed Wyoming-Cloverdale transmission line, AEP requested independent experts from West Virginia University and Virginia Polytechnic Institute and State University (the "Universities Study Team" or "UST"), to analyze and determine the most environmentally sound route from the Wyoming Station to the Cloverdale Station. The route developed by the UST traversed a number of areas under federal jurisdiction, including the Jefferson National Forest (JNF), the Appalachian National Scenic Trail ("AT"), and the New River. As a result, the federal agencies determined that their consideration of the respective permits and rights-of-way to cross-lands under federal jurisdiction required compliance with NEPA, including preparation of an EIS. The federal agencies published the original Notice of Intent ("NOI") to prepare the EIS on November 21, 1991. Subsequently, seven revised NOIs were published extending the original February 1993 publication date for the DEIS.

In 1992, Public Law 102-525 designated 19.2 miles of the New River, including the area of the original proposed Wyoming-Cloverdale crossing, for study under the Wild and Scenic Rivers Act, 16 U.S.C. § 1276(a) (the "New River Study Area"). In 1994, a study by the NPS determined that the area of the New River designated for study was eligible for classification as a scenic river in the National Wild and Scenic Rivers System. By 1996, the NPS concluded that it would recommend denial of the necessary permits for any proposed transmission line crossing this area of the New River as being inconsistent with the purposes of the Wild and Scenic Rivers Act.

The federal agencies published the DEIS on June 18, 1996. The DEIS considered fourteen alternatives: AEP's proposed action, twelve alternatives developed by the federal agencies to the proposed action, and the No Action Alternative. The Forest Service and NPS selected as their preferred alternative the No Action Alternative, based on the agencies' determination of potential significant environmental impacts to the JNF, the AT, and the New River. Under this alternative, no transmission line would be constructed and the need for the proposed action would not be met.

In order to construct the proposed transmission line, in addition to any necessary federal permits, AEP was also required to obtain certificates of public convenience and necessity ("CPCN") from the Virginia State Corporation Commission ("VSCC") and from the West Virginia Public Service Commission ("WV PSC"). A CPCN addresses two issues; confirmation of the need for the line and authorization of a construction route within areas under the jurisdiction of the relevant state commission. On September 30, 1997, AEP filed new applications with the VSCC and WV PSC to construct the Wyoming-Cloverdale line along a modified 132-mile route that would avoid the New River Study Area and Sinking Creek Valley, and reduce impacts on the JNF. On May 27,1998, the West Virginia PSC issued a CPCN approving the construction of the Wyoming-Cloverdale transmission line along the new preferred corridor in West Virginia. In response to a motion filed by the VSCC Staff, by ruling entered on September 22, 1998, the VSCC Hearing Examiner directed AEP to conduct detailed need and environmental studies on an alternative project between the Company's Wyoming Station and a point at or east of the Company's Jacksons Ferry Station in Wythe County, Virginia. AEP again retained the UST to develop a route with the least overall environmental impact. The Company's report on the Wyoming-Jacksons Ferry alternative route was filed with the VSCC on May 7, 1999. The SCC Hearing Examiner considered both the Wyoming-Cloverdale project and the Wyoming-Jacksons Ferry alternative project at an evidentiary hearing held in May 2000. After considering extensive evidence, the Hearing Examiner recommended and the VSCC determined that the best option for reinforcing the transmission system was the Wyoming-Jacksons Ferry alternative project. The Wyoming-Jacksons Ferry corridor is approximately 90 miles in length, has fewer adverse environmental impacts than earlier proposed project routes, particularly with respect to the JNF and the AT, and avoids crossing the section of the New River deemed eligible for inclusion in the National Wild and Scenic Rivers System. The VSCC issued an Order on May 31, 2001, granting AEP a CPCN, which included a determination of need, approved the private land portion of AEP's route in Virginia, and granted AEP authority to construct the Virginia portion of the Wyoming-Jacksons Ferry transmission line. The Order includes detailed mitigation requirements, including but not limited to measures with respect to the potential impacts on threatened and endangered species, including all bat species, natural heritage resources, karst areas, and caves. These mitigation measures evidence the extent to which the VSCC considered potential environmental impacts and responded to the concerns of the public and agencies with jurisdiction over environmental resources.

b. An approximately 90 miles long 765 kV line will connect the Wyoming 765 kV Station, located near Oceana, West Virginia,to the Jacksons Ferry 765 kV Station in Wythe County, Virginia. Right-of-way acquisition is underway, and initial right-of-way clearing began in early December 2003. AEP anticipates that this circuit will be in-service by June 2006. Joining PJM is not expected to impact the construction of the Wyoming - Jacksons Ferry 765 kV line.

WITNESS: J Craig Baker

Kentucky Power
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REQUEST

Refer to page 24 of the Baker testimony, lines 4-5. For the past 2 years (2002-2003) provide the number of hours in which there have been curtailments impacting Kentucky Power customers.

RESPONSE

For the period mentioned (2002-2003), there have been no curtailments that impacted Kentucky Power customers.

WITNESS: J Craig Baker

2

Kentucky Power
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American Electric Power

REQUEST

Refer to Exhibits JCB-2 and JCB-5 to the Baker Testimony, which show that limited participation in PJM increases AEP's net benefits over the 2004-2008 period by 50 percent, or $95 million, compared to its full participation in PJM. Explain whether such limited participation is AEP's preference. If no, explain why limited participation is not AEP's preference.

RESPONSE

AEP's preference is to join PJM in the manner described in its application in this case, for the reasons described in the evidence submitted in this case. The limited participation scenario has not been offered to AEP as an alternative for joining PJM. It was raised by AEP as a possible starting point for a dialogue among regulators, including the Federal Energy Regulatory Commission and the Kentucky Public Service Commission, as a means of resolving the dispute now pending before FERC in Docket No. ER03-262-009. To the best of AEP's knowledge, no regulatory body has initiated or participated in any such dialogue.

WITNESS: J Craig Baker

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American Electric Power

REQUEST

Identify the discount rate used in the exhibits to Baker's testimony, and provide the derivation of this rate.

RESPONSE

All dollars (inflows and outflows) are reported on a nominal basis by year, no discount rate was applied.

WITNESS: J Craig Baker

2

Kentucky Power
d/b/a
American Electric Power

REQUEST

Summarize the current status of zonal vs. postage stamp rates in PJM and explain if the transmission investment base used in calculating transmission rates will change for Kentucky Power's customers if AEP joins PJM.

RESPONSE

PJM employs zonal rates for transmission service by loads within the RTO region. The transmission investment base used in calculating transmission rates for Kentucky Power's customers will not change upon AEP joining PJM.

WITNESS: J Craig Baker

Kentucky Power
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American Electric Power

REQUEST

Describe how PJM allocates the cost of system upgrades related to new generator interconnections and explain whether this issue is being reconsidered.

RESPONSE

The allocation of the cost of system upgrades related to new generation interconnections is described in the Large Generator Interconnection Agreement filed on January 20, 2004 by PJM in FERC Docket No. RM02-1-000 which can be found at the following web site: http://www.pjm.com/documents/downloads/ferc/2004docs/january/20040120-order-2003-compliance-filing.pdf. To the best of AEP's knowledge, this issue is not being reconsidered.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Describe how PJM allocates the cost of generic system upgrades and indicate whether this issue is currently being reconsidered.

RESPONSE

Transmission system upgrade projects identified in the PJM Regional Transmission Planning Process as needed for "generic" reliability will be constructed by the transmission owner(s) in the zone(s) where the facilities are required and rolled into the transmission rates for that zone, unless the project is funded as a merchant/economic transmission upgrade pursuant to PJM Schedule 12/12A. A copy of the presently effective Schedule 12/12A is attached. These schedules are effective, subject to possible change and refund/rebill obligations, while rehearing procedures continue, as to the schedules final disposition in FERC Docket No. RT01-2-009, *et. al.*

WITNESS: J Craig Baker

SCHEDULE 12

TRANSMISSION ENHANCEMENT CHARGES

(a) The Regional Transmission Expansion Plan periodically developed pursuant to Schedule 6 of the Operating Agreement from time to time may designate one or more of the Transmission Owners to construct and own or finance Required Transmission Enhancements (as defined in Section 1.38B). Section 1.7 of Schedule 6 of the Operating Agreement recognizes that Transmission Owners, subject to obtaining any necessary regulatory approvals, may seek to recover the costs of Required Transmission Enhancements and obligates Transmission Provider to collect on behalf of Transmission Owner(s) any charges established by Transmission Owners to recover the costs of Required Transmission Enhancements. Each charge by a Transmission Owner for recovery of the costs of Required Transmission Enhancements under this Schedule 12 shall be a monthly charge based on all costs and any FERC-approved incentives associated with a particular Required Transmission Enhancement for which the Transmission Owner is responsible. Each such charge is hereafter referred to as a "Transmission Enhancement Charge."

(b) In the event that any Transmission Owner recovers the cost of a Required Transmission Enhancement through a Transmission Enhancement Charge, a corresponding Transmission Enhancement Charge Rate, as described below, shall be established in this Schedule 12. In recognition that the benefits to competition, system reliability and/or operational performance of Required Transmission Enhancements will accrue to particular market participants, Transmission Provider shall designate in this Schedule 12 the customers using Point-to-Point Transmission Service and/or Network Integration Transmission Service that will be subject to each such Transmission Enhancement Charge (hereafter "Responsible Customers"). Such designations shall be the same as those made for the relevant Required Transmission Enhancement in the Regional Transmission Expansion Plan.

(c) Transmission Provider shall identify in this Schedule 12 the Required Transmission Enhancement(s) to which each Transmission Enhancement Charge corresponds. Transmission Provider shall collect all applicable Transmission Enhancement Charges from each Responsible Customer on a monthly basis. The monthly charge for each Responsible Customer shall equal the Monthly Transmission Enhancement Charge Rate, as defined below, times the total quantity in MWhs of energy delivered during such month by such user as a Transmission Customer for Point-to-Point Transmission Service or Network Integration Transmission Service under this Tariff. Each Transmission Enhancement Charge Rate shall be determined in accordance with the formula:

$$\text{MTECR} = \frac{\text{TEC}}{\text{RCTHTU}}$$

where:

MTECR is the Monthly Transmission Enhancement Charge Rate;

TEC, Transmission Enhancement Charge, is the applicable Transmission Owner's Transmission Enhancement Charge for the month for which MTECR is being calculated; and

RCTHTU, Responsible Customers Total Hourly Transmission Usage, is the actual total quantity in MWhs of energy delivered under Point-to-Point Transmission Service or Network Integration Transmission Service, during the month for which MTECR is being calculated, by all Responsible Customers for the relevant Transmission Enhancement Charge, provided, however, that MTECR shall be subject to adjustment, in the same manner as other charges for transmission service under the Tariff, as needed to reflect corrections or revisions to metered energy quantities of any Responsible Customer.

(d) Responsible Customers shall pay Transmission Provider all applicable Transmission Enhancement Charges as provided under this Schedule 12 in addition to all other charges for transmission service for which such customers are responsible under the Tariff. As and to the extent that Transmission Provider collects revenues from Responsible Customers under a Transmission Enhancement Charge under this Schedule 12, it shall remit or credit such revenues to the Transmission Owner(s) that established such charge.

SCHEDULE 12A

CALCULATION OF TRANSMISSION ENHANCEMENT CHARGES

(a) The Transmission Enhancement Charge applicable to Responsible Customers designated in Schedule 12 with respect to a particular Required Transmission Enhancement shall be calculated in accordance with this Schedule 12A.

(b) The Transmission Enhancement Charge applicable to a particular Required Transmission Enhancement shall be equal TO one-twelfth of the sum of the Annual Transmission Enhancement Revenue Requirements of all applicable Transmission Owners with respect to the particular Required Transmission Enhancement calculated in accordance with sections (c) and (d) below.

(c) Each applicable Transmission Owner's Annual Transmission Enhancement Revenue Requirement with respect to a particular Required Transmission Enhancement shall be determined by multiplying that Transmission Owner's Required Transmission Enhancement Investment by its Required Transmission Enhancement Carrying Charge Rate for the applicable year following the year the particular Required Transmission Enhancement is placed in service. The Transmission Owner's Required Transmission Enhancement Investment shall be the amount, determined in accordance with the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Federal Power Act, which would be includable in rate base for the Required Transmission Enhancement as of the date that the Required Transmission Enhancement is placed in service. Year 1 shall commence on January 1 of the year following the year the Required Transmission Enhancement is placed in service.

(d) The respective Required Transmission Enhancement Carrying Charge Rates applicable to each Transmission Owner shall be as set forth from time to time in Schedule 12A-1 through Schedule 12A-12.

(e) The Transmission Provider shall determine annually the amount of Transmission Enhancement Charges applicable to each Responsible Customer that is required to collect the Annual Transmission Enhancement Revenue Requirement of each Transmission Owner with respect to each Required Transmission Enhancement.

(f) The Transmission Provider shall pay or credit all Transmission Enhancement Charge revenues collected with respect to a particular Required Transmission Enhancement to the Transmission Owner(s) having Annual Transmission Enhancement Revenue Requirements with respect to that Required Transmission Enhancement. Where more than one Transmission Owner has an Annual Transmission Enhancement Revenue Requirement with respect to a Required Transmission Enhancement, the revenue collected with respect to that Required Transmission Enhancement shall be paid or credited in proportion to each such Transmission Owner's respective Annual Transmission Enhancement Revenue Requirement. No adjustment shall be made as a result of over- or under-collection in any prior year.

(g) Each Transmission Owner with Annual Transmission Enhancement Revenue Requirements determined pursuant to this Schedule 12A shall annually provide to the Transmission Provider, on or before November 1 of each year, the following:

(1) the Required Transmission Enhancement Investment for each Required Transmission Enhancement for which the Transmission Owner has or will have an Annual Transmission Enhancement Revenue Requirement; and

(2) the year the Transmission Owner placed in service or will place in service each Required Transmission Enhancement for which the Transmission Owner has or will have an Annual Transmission Enhancement Revenue Requirement;

(h) Nothing contained in Schedule 12 or this Schedule 12A shall limit the right of a Transmission Owner under Section 205 of the Federal Power Act and consistent with the Transmission Owners Agreement to file with the Commission individually and unilaterally to recover the cost of a Required Transmission Enhancement in a manner other than that specified in Schedule 12 or this Schedule 12A, including but not limited to, to recover rate enhancements or incentives not specified herein and to recover the cost of a Required Transmission Enhancement through its rates under Schedules 7 and 8 and Attachment H.

Kentucky Power
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American Electric Power

REQUEST

Describe PJM's curtailment procedures for both transmission- and generation-related emergencies.

RESPONSE

PJM's curtailment procedures for Transmission related events, are specified in PJM Manual #13: Emergency Operations, Section 9 Transmission Loading Relief, posted on PJM's website at www.pjm.com:

> PJM monitors designated transmission facilities within the PJM RTO as well as timelines with adjacent interconnected control areas. When PJM determines overload conditions exist on any designated facility, or would exist for the first contingency loss of another facility, PJM will take all necessary action(s) to restore transmission facilities within operating security limits. If PJM has re-dispatched internal generation to the extent possible and more relief is needed, PJM will perform the following actions:
>
> - Invoke the NERC Transmission Loading Relief Procedure
> - Curtail external transactions and/or charge external customers for the cost of congestion as specified in the PJM Open Access Transmission Tariff
>
> If all transactions for which transmission customers have elected not to pay through congestion have been curtailed and further relief is still required on the transmission facility, PJM will begin to curtail all transactions (internal and external) for which transmission customers have elected to pay through congestion, in priority order.
>
> For Generation related events PJM monitors designated transmission facilities within the PJM RTO as well as tielines with adjacent interconnected control areas. When PJM determines overload conditions exist on any designated facility, or would exist for the first contingency loss of another facility, PJM will take all necessary action(s) to restore ·
> Invoke the NERC Transmission Loading Relief Procedure

transmission facilities within operating security limits. If PJM has re-dispatched internal generation to the extent possible and more relief is needed, PJM will perform the following actions:

Curtail external transactions and/or charge external customers for the cost of congestion as specified in the PJM Open Access Transmission Tariff

If all transactions for which transmission customers have elected not to pay through congestion have been curtailed and further relief is still required on the transmission facility, PJM will begin to curtail all transactions (internal and external) for which transmission customers have elected to pay through congestion, in priority order.

PJM's curtailment procedures for Generation related events, are specified in PJM Manual #13: Emergency Operations, Section 2 Capacity Conditions, posted on PJM's website at www.pjm.com:

The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability. These measures involve:

- loading generation that is restricted for reasons other than cost
- recalling non-capacity backed off-system sales
- purchasing emergency energy from participants / surrounding pools
- load relief measures

The procedures to be used under these circumstances are described in the general order in which they are applied. Due to system conditions and the time required to obtain results, PJM dispatcher may find it necessary to vary the order of application to achieve the best overall system reliability. Issuance and cancellation of emergency procedures are broadcast over the "ALL-CALL" and posted to selected PJM web-sites. Only affected systems take action. PJM dispatcher broadcasts the current and projected PJM RTO status periodically using the "ALL-CALL" during the extent of the implementation of the emergency procedures.

Exhibit 5 presents the general order for implementing shortage actions:

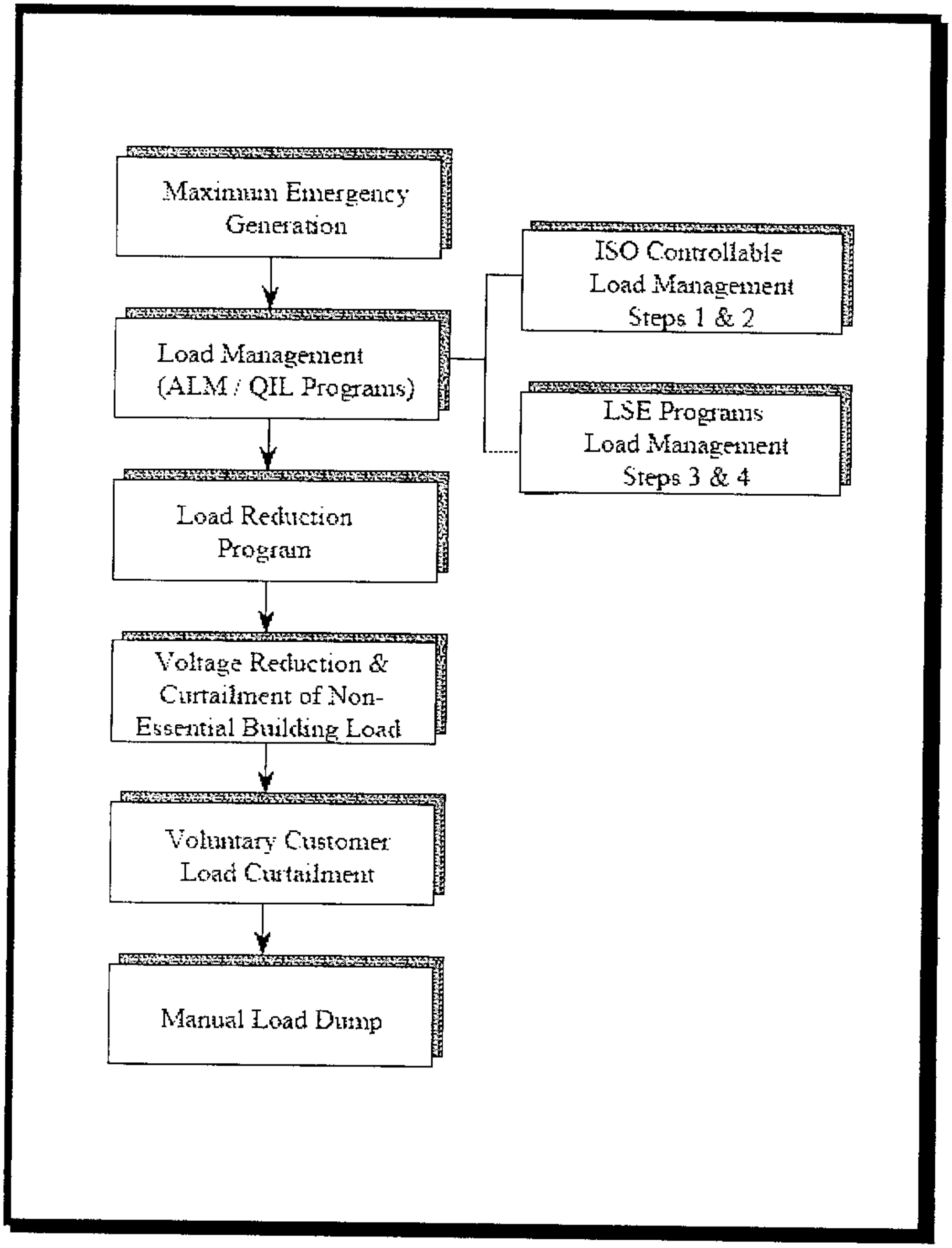

Exhibit 5: Shortage Actions

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 2 of the Direct Testimony on Rehearing of Hoff Stauffer ("Stauffer Testimony").

a. Explain whether the study and report contained in Exhibit HS-1 to the Stauffer Testimony, which was conducted by CERA for the AEP-East zone, is in any way different from the benefits-cost study that is being prepared for the Virginia State Corporation Commission ("VSCC").

b. If Exhibit HS-1 is not that study, provide the study being prepared for the VSCC.

RESPONSE

a. It is the same basic study. As a result of orders issued by the Virginia State Corporation Commission (SCC), the CERA study included with the testimony filed with the SCC differed in two primary respects from the study included with the filing in this proceeding. First, CERA performed an analysis for one additional year, 2013, to support the SCC's requirement that the study period include the years 2004 through 2014. Second, CERA analyzed an additional scenario (AEP participating in PJM but not Dominion Virginia Power) to meet the SCC's requirement that the study include that scenario. Refer to the supplemental direct testimonies of J. C. Baker and Hoff Stauffer filed with the SCC on January 20, 2004 in Case No. PUE-2000-00550.

b. APCo's cost/benefit analysis filed with the SCC on January 20, 2004, including Mr. Stauffer's Exhibit __, Schedule 1, can be found in the AEP web page, http://aep.com/legal/virginia

WITNESS: J Craig Baker

Kentucky Power
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REQUEST

Refer to page 6 of Exhibit HS-1 regarding future wheeling rates. Explain why "CERA expects the wheeling rate situation to work out" as described in the first paragraph immediately following the identification of the two scenarios being assessed.

RESPONSE

CERA expects the wheeling rate situation to work out as simulated in the CERA study based on CERA's experience and professional judgment, and CERA's long time working relationships with the transmission professionals in all of the affected regions including discussions with such professionals and others in the context of the work on the Grounded in Reality study.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 6 of Exhibit HS-1 regarding the period of time covered by the CERA study. Explain why runs were conducted for 3 years (2004, 2006, and 2008) of the 5-year period with the values for intermediate years being interpolated. Why not conduct runs for all 5 years or, conversely, why not conduct runs for only 2004 and interpolate the values for 3 intermediate years?

RESPONSE

This approach was used to minimize the number of GE-MAPS runs, to the extent possible, in order to minimize the cost of the study without compromising the study results and expedite the study submission to the Commission.

WITNESS: J Craig Baker

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Kentucky Power
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REQUEST

Refer to page 4 of Exhibit HS-1 regarding the statement that "(t)o a large extent, the costs and benefits of joining an RTO are driven by the elimination of wheeling rates between regions, including AEPs through and out rates." If this is true, why not simply eliminate wheeling rates and avoid the expense of RTO administrative costs?

RESPONSE

AEP is required to join a RTO, see Mr. Baker's testimony at page 3, lines 5-7. See also Mr. Baker's testimony at Page 6, lines 16-21.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 6 of Exhibit HS-1 regarding the statement that the "wheeling rate in commitment is $3 higher than in dispatch, representing inefficiencies associated with bilateral markets in the area where there is no energy market." Provide an explanation for this statement, to include the following:

Identify and describe the "inefficiencies associated with bilateral markets."

RESPONSE

The "inefficiencies associated with bilateral markets" as discussed in testimony refers to a comparison of bilateral markets to an organized market with centralized unit commitment and economic dispatch over a larger region, such as the PJM RTO footprint. Bilateral markets in the context of page 6 of Exhibit HS-1, such as in the AEP control area under Case II (AEP stand-alone) are smaller than the resultant larger PJM market in Case I with AEP in PJM. In the non-RTO environment, utilities commit and dispatch units independently for their own internal load first based on the information available from their own internal resources as well as from the bilateral markets. Smaller sized pools with bilateral transaction relationships tend to result in a less efficient solution due to lack of timely information and liquidity as compared to a larger pool, such as the PJM market where the price is transparent and there is flexibility to select efficient resources from a larger pool.

WITNESS: Hoff Stauffer

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 6 of Exhibit HS-1 regarding the statement that the "wheeling rate in commitment is $3 higher than in dispatch, representing inefficiencies associated with bilateral markets in the area where there is no energy market." Provide an explanation for this statement, to include the following:

Explain how the $3.00 amount was determined.

RESPONSE

When there is not a unified market with centralized unit commitment and dispatch (such as PJM), the individual, smaller control areas will not be able to optimize commitment because they have inadequate information about unit economics and transmission options in other control areas. Hence, unit commitment will be less optimal, tending to commit too much in high-cost regions and too little in low-cost regions. Without the $3 wheeling rate in commitment, MAPS would commit optimally. We use the $3 charge to simulate the inefficiencies that exist when there is no centralized unit commitment.

WITNESS: Hoff Stauffer

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 6 of Exhibit HS-1 regarding the statement that the "wheeling rate in commitment is \$3 higher than in dispatch, representing inefficiencies associated with bilateral markets in the areas where there is no energy market." Provide an explanation for this statement, to include the following:

Provide the tariff that shows AEP's current transmission service rate to be \$4.25 per MWh.

RESPONSE

The values of \$7.25 and \$4.25 were hurdle rates developed by CERA in evaluating unit commitment and real-time dispatch. They are not directly related to AEP's wheeling rate. While the \$4.25 rate used in the study differs slightly from the rates as shown in the attached Company tariff sheets, we do not believe that this slight difference impacts the study results in any material way.

WITNESS: J Craig Baker

SCHEDULE 1

SYSTEM SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. System Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for System Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Transmission Customers taking service under Part II or Part III may elect either Hourly Scheduling Service or Dynamic Scheduling Service.

Hourly Scheduling Service is a service that employs specific hourly schedules for the transmission of energy by coordinating the event among the affected Control Areas. The Transmission Customer provides a schedule, from midnight to midnight, containing up to 24 hourly values that signify the desired amount of energy to be transmitted from the supply host Control Area to a single load host Control Area. The service is different from Dynamic

Scheduling Service in that the scheduled amount is not changed by a dynamic real-time signal, but is a fixed hourly amount. Hourly Scheduling Service includes set up, modification, confirmation, implementation, accounting and necessary reporting of the transaction, as well as the use of supporting hardware and software systems for control and tracking of schedules. Schedules shall be made in whole MW increments.

Dynamic Scheduling Service enables remote load regulation for a load, by effecting adjustments in schedules for energy transfers where the desired power level of the transaction is communicated by a real-time signal signifying an amount of generation, an amount of load, a regulation requirement, or a share of the output of a generator. The real-time signal indicating the dynamic schedule amount must be provided simultaneously to both the sending and receiving Control Areas for incorporation into their respective real-time control systems. Both sending and receiving Control Areas must integrate the signal and agree on the hourly energy transfers. The Transmission Customer is responsible for telemetry and signal processing costs. Any charges imposed by the Transmission Provider for telemetry and signal processing shall be stated in the Service Agreement. Dynamic Scheduling Service must be arranged with both the sending and receiving Control Areas. Dynamic Scheduling Service includes set up, modifications, communications between sending and receiving Control Areas, confirmation, accounting and necessary reporting of the transactions, as well as supporting hardware and software systems for control and tracking of schedules. Schedules shall be made in whole MW increments.

The rates for System Scheduling, System Control and Dispatch Service for transmission to a delivery point located in the AEP East Zone or the AEP West Zone (SPP) shall be up to:

	AEP East Zone	AEP West Zone (SPP)
Per MW-month	$57.71	$30.00
Per MW-week	$13.28	$ 6.90
Per MW-day	$ 1.89	$ 0.99
Per MW-hour	$ 0.08	$ 0.04

Such rates shall be applied to the amount of Reserved Capacity for transmission service under Part II and to the amount of monthly Network Load for transmission service under Part III.

SCHEDULE 2

SYSTEM REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, System Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of System Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

System Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. After the ERCOT Service Date, the Transmission Customer must obtain ERCOT Ancillary Services to serve load in ERCOT under the ERCOT Protocols. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission

Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

The rates for System Reactive Supply and Voltage Control from Generation Sources Service for transmission to a delivery point located in the AEP East Zone or the AEP West Zone (SPP) shall be up to:

	AEP East Zone	AEP West Zone (SPP)
Per MW-month	$ 73.00	$48.05
Per MW-week	$ 16.80	$11.06
Per MW-day		
On-Peak	$ 3.36	$ 2.21
Off-Peak	$ 2.40	$ 1.58
Per MW-hour		
On-Peak	$ 0.21	$ 0.14
Off-Peak	$ 0.10	$ 0.07

Such rates shall be applied to the amount of Reserved Capacity for transmission service under Part II and to the amount of monthly Network Load for transmission service under Part III. Although the Transmission Customer is required to take this ancillary service from the Transmission Provider, the Transmission Customer may reduce the charge for this service to the extent it can self supply reactive power.

The total charge in any day, pursuant to an hourly service reservation, shall not exceed the applicable rate for daily service specified above for the applicable Transmission Provider Control Area, times the highest amount of hourly service reserved in any hour during such day. In addition,the total charge in any week pursuant to a reservation for hourly or daily service shall not exceed the rate for weekly service specified above for the applicable Transmission Provider Control Area, times the highest amount of hourly or daily service reserved in any hour or day during such week.

The Off-Peak Period shall be all hours of Saturday, Sunday, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day and the hours between 11:00 p.m. and 7:00 a.m. local time on all other days. The On-Peak Period shall be all hours other than the hours in the Off-Peak Period.

SCHEDULE 8

NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the charges set forth below. The rates for Non-Firm Point-to-Point Transmission Service to points of delivery located in the AEP East Zone or the AEP West Zone shall be up to:

	AEP East Zone	AEP West Zone
Per MW-month	$ 1,420.00	$ 1,050.00
Per MW-week (a)	$ 326.79	$ 241.64
Per MW-day		
On-Peak	$ 65.36	$ 48.33
Off-Peak	$ 46.68	$ 34.52
Per MW-hour		
On-Peak	$ 4.09	$ 3.02
Off-Peak	$ 1.95	$ 1.44

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the weekly rate specified above times the highest amount in megawatts of Reserved Capacity in any day during such week.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the applicable daily rate specified above times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the weekly rate specified above times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

An Eligible Customer that takes ERCOT Regional Transmission Service under Part IV of this Tariff and also takes Transmission Service under Part II of the SPP Tariff to import power and energy into ERCOT to serve its customers in ERCOT shall have its facilities charges under Attachment T of the SPP Tariff reduced by 45.27% for transmission through the AEP West Zone.

A Transmission Customer that takes transmission service under Part II of this Tariff in conjunction with the use of the SPP Tariff to transmit energy from a Point of Receipt located in ERCOT to a Point of Delivery located outside of ERCOT, except to a Point of Delivery located in the AEP East Zone, shall in addition to charges due under the SPP Tariff pay facilities charges under this Schedule 8 that are reduced by 54.73%.

For purposes of this Schedule 8, the Off-Peak Period shall be all hours of Saturday, Sunday, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day and the hours between 11:00 p.m. and 7:00 a.m. local time on all other days and the On-Peak Period shall be all hours that are not in the Off-Peak Period.

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 6 of Exhibit HS-1 regarding the statement that the "wheeling rate in commitment is $3 higher than in dispatch, representing inefficiencies associated with bilateral markets in the area where there is no energy market." Provide an explanation for this statement, to include the following:

Provide the tariff that show that the "join PJM scenarios" would still result in a transmission service rate of $4.25 or the PJM practice that establishes that existing transmission service rates of new members would be retained upon joining PJM.

RESPONSE

The PJM tariff charges zonal rates for load within the zone, and a PJM-wide "Border Rate" for transactions that exit PJM. When AEP becomes a transmission zone under the PJM tariff, AEP's current transmission service rate for transactions that exit or go through the AEP system will no longer apply. Instead, the PJM Border Rate will be applicable for transactions that exit the PJM region (except to points within the PJM, ComEd, DP&L, MISO, Illinois Power or Ameren systems, where out and through charges will be eliminated and replaced by SECA charges). The PJM Border Rate that will apply at the time AEP joins PJM is not presently known.

WITNESS: J Craig Baker

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to page 6 of Exhibit HS-1 regarding the statement that the "wheeling rate in commitment is $3 higher than in dispatch, representing inefficiencies associated with bilateral markets in the area where there is no energy market." Provide an explanation for this statement, to include the following:

What is the weighted average transmission service rate for the PJM member companies?

RESPONSE

The currently effective network integration transmission service rate for each of the present PJM zones in $ per MW-year is as follows:

Atlantic City Electric	$ 17,578
Baltimore Gas & Electric	$ 13,020
Delmarva Power	$ 15,300
The GPU Group: Jersey Central P&L, Metropolitan Edison and PennElec	$ 15,112 each
PECO	$ 20,942
PP&L	$ 19,063
Potomac Edison	$ 16,654
PSE&G	$ 17,631
Allegheny Power	$ 17,895
Rockland Electric	$ 32,114

These rates are charged each month based on the customer's load in the hour of the PJM regional peak load during the prior year. The PJM OATT does not list any weighted average rate, but historic and projected load information is available on the PJM website at http://www.pjm.com/documents/downloads/reports/2003-load-report.pdf. A worksheet showing the calculation of the 2002 summer normal peak load (page 38 - 39 of 2003 PJM Load Forecast Report) weighted average rate for PJM is attached.

WITNESS: J Craig Baker

Calculation of PJM
Summer 2002 Normal Peak
Load Weighted Average
Zonal Transmission Rate

PJM Zone	NTS Rate $ per MW-Yr.	Sumr. Nrm. 2002 Pk. (MW)	Load Share %	Load Weighted NTS Rate $ per MW-Yr.
ACE	$ 17,578.00	2,598	4.069%	$ 715.31
BGE	$ 13,020.00	6,731	10.543%	$ 1,372.71
Dlmrva	$ 15,300.00	3,827	5.994%	$ 917.14
FE/GPU	$ 15,112.00	10,940	17.136%	$ 2,589.56
PECo	$ 20,942.00	8,091	12.673%	$ 2,654.04
PL Grp (PL&UGI)	$ 19,063.00	6,804	10.657%	$ 2,031.62
PEPCo	$ 16,654.00	6,203	9.716%	$ 1,618.11
PSE&G	$ 17,631.00	10,064	15.764%	$ 2,779.29
APS	$ 17,895.00	8,175	12.805%	$ 2,291.43
Rockland	$ 32,114.00	410	0.642%	$ 206.24
Average	$ 15,442.42	63,843	100.000%	$ 17,175.44